ENERGY FOR THE FUTURE

Working Paper Number Three

COMPETING FOR POWER:

A SURVEY on COMPETITIVE PROCUREMENT SYSTEMS and BLUEPRINT FOR THE FUTURE

July 1991

NATIONAL INDEPENDENT ENERGY PRODUCERS

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THIRD EDITION OF NIEP STUDY
OF COMPETITIVE PROCUREMENT IN ELECTRIC GENERATION

he emergence of independent power suppliers (both Qualifying Facilities under the Public Utility Regulatory Policies Act of 1978 (PURPA) and other non-traditional wholesale suppliers such as IPPs) transformed electric power markets in the 1980s. The abundance of new supply opportunities, with developers prepared to compete to shield ratepayers from construction and operating risks through fixed price contracts, often at well below the purchasing utility's avoided cost, led state commissions and utilities to turn to competitive procurement as the dominant method for selecting the builders of new electric capacity.

Since the implementation of PURPA in the early 1980s, independent power producers have secured contracts through four procurement methods: 1) standard offer contracts and first come-first served avoided cost contracts, limited to QFs; 2) arms-length voluntary negotiation without exercise of PURPA mandatory purchase rights; 3) formal competitive bidding open to both QFs and other wholesale suppliers; and 4) competitive negotiation in which bidding criteria are used to select a negotiating pool. Independent non-utility generation, with contracts obtained through these methods, accounted for 50 percent of the new capacity brought on line in the United States in 1989 and 1990.

In its two previous reports on competition in generation (1987 and 1990), NIEP described and analyzed the competitive bidding programs either adopted or under development by utilities and state commissions throughout the country. Drawing upon insights from that analysis, NIEP proposed model bidding guidelines designed to ensure fair competition among power suppliers which would deliver least cost, reliable power to the nation's ratepayers.

In this study, NIEP focuses on the actual practice of bidding from the perspective of companies which have actively competed in the solicitations. Drawing upon the experiences of bidders, as well as reactions from utilities and state commissions, NIEP recommends policies and guidelines which respond to problems identified by bidders in current competitive programs. Specifically NIEP recommends moving away from price-driven procurement methods with rigid selection criteria, and towards more flexible and varied systems. Moreover, competitive procurement systems should put more emphasis on negotiation on the basis of more subjective standards while maintaining a balance of a high level of accountability.

In its review of competitive procurement, NIEP has focused on five key states (New Jersey, Virginia, Florida, California, and Washington) which reflect geographic diversity, different approaches to, and different experiences with, bidding. In these target states, NIEP sent questionnaires to both the commissions and utilities that hosted bids, as well as the companies that responded to RFPs with proposals.

Current Status of Bidding

Since 1984, 36 states have either adopted or are in the process of adopting competitive procurement procedures to determine their future electric needs. As of May 1, 1991, 28 states either: 1) have adopted bidding; 2) permit jurisdictional bidding; 3) are modifying existing bid rules; or 4) are developing a bid program currently. Four states are considering adopting a limited bid process, restricted to demand side management and conservation. Within investor-owned utilities, twelve (in ten states) have initiated bidding programs without prior approval of their state commissions.

Bidding has also spread among public power entities. A total of 17 government agencies, rural electric cooperatives and public utilities have issued Requests for Proposals (RFPs). The Rural Electrification Administration, which offers loans to rural electric cooperatives (RECs), now requires that RECs who need capacity must procure it through bidding.

Since 1984, 36 states have either adopted or are in the process of adopting competitive procurement procedures to determine their future electric needs.

In the last seven years, 1,344 supply-side projects have bid over 104,000 megawatts. In all, 67 RFPs have been issued by utilities, representing a total request for 19,273 megawatts. In the 42 solicitations where winners have been selected as of May 1991, 11,946 megawatts have been awarded to 315 projects. Of the 67 projects procured through bidding which have come on line, 56 were developed on schedule and only 11 were delayed (an average of nine months). Delays were more often a function of securing air quality permits and public opposition than financing, which has produced few problems.

Bidders' Critiques of Bidding

The NIEP survey of bidders revealed widespread dissatisfaction with the current state of bidding. Utilities and state commissions, on the other hand, were generally comfortable with results to date. The major shortcomings of bidding identified in the survey include:

- Restrictions on developers' creativity in the design, operation and financing of power plant options;
- Too high an emphasis on price, with the effect of driving profit margins so low that contract creativity, technological innovation, project feasibility and reliability may be shortchanged;
- Failure of utilities in different states to adopt standard contract terms which have withstood the test of time and are less likely to be challenged by project finance lenders; and
- Delay in completing bids, inexperience, "lack of seriousness," lack of appeal rights, and politicization of bidding by public power entities.

Bidders, as a group, expressed a preference for the option of contracting with utilities outside a formal bidding procedure, especially where:

- Bidding programs contained a bias against high capital/low fuel cost projects with long lead times;
- There is difficulty in accommodating the timing of bid solicitations to projects, such as waste to energy and hydro facilities, which may be hostage to licensing and municipal contracting processes beyond their control; and,
- Bidding is not designed to encourage technologies or projects with external societal benefits, such as some renewables or demand-side management programs.

While valuing the opportunity for contracting outside bidding, most bidders recognized a need for a balanced system which includes the flexibility to accommodate projects ill suited for bidding while maintaining fairness, predictability and accountability in a selection process that compares the relative merits of all options, supply and demand side, on an integrated basis.

Environmental Issues Affecting the Design of Bidding Programs

In recent years, regulatory commissions and utilities have begun to show greater concern for the environmental impact of energy production. This concern is evident in the design and structure of bidding programs. Specifically, utilities and commissions are struggling to determine the impact on design of bidding of both unforeseen changes in regulatory compliance costs (resulting from new environmental standards) and consideration of environmental externalities. Bidders, state commissions and utilities were polled regarding these two issues.

The significance of the treatment of unforeseeable regulatory compliance costs is potentially great. For instance, under traditional cost-of-service (or cost-plus) ratemaking, utilities are entitled to recoup all prudently incurred costs directly from the ratepayers. By contrast, cost recovery by contract power suppliers is generally fixed. In the evaluation of resource alternatives, this treatment can create a competitive advantage for utility cost-of-service plants.

Bidders reported a variety of responses to regulatory changes, with the vast majority noting that their contracts do not have any type of pass-through provisions for costs associated with regulatory compliance. Developers expressed a preference for the allowance of pass-through provisions in power sales contracts. Utilities were split on the question, with some suggesting that commissions should permit negotiations between developers and utilities to resolve treatment of these costs. State commissions, however, stood firmly opposed to allowing automatic pass-through of these costs except in the most extraordinary circumstances.

Consideration of externalities is another emerging issue in bidding. As of July 1990, 17 states had adopted procedures on the treatment of externalities and seven were in the process of doing so. Additionally, five of the 17 require some type of consideration of externalities in their bidding programs. The ways in which states sought to evaluate externalities included: 1) qualitative methods which give preference to less polluting technologies; 2) allowing cleaner resources to discount their prices relative to other technologies; and, 3) quantification of costs based on actual emissions.

In making recommendations, a pervasive theme from all respondents was that some type of objective measure of externalities was more preferable than a subjective one (such as a policy which stated a preference for certain technologies). Nevertheless, respondents also cautioned against rigid policies which do not reflect the subtle yet important differences which distinguish projects. Suggestions included considerations of:

1) Location of pollutants: the social cost of a facility in a rural area should be distinguished from a similar facility in an urban area.

2) Offsetting externalities: bidders can compensate for externalities by proposing to plant trees or buy land for conservation.

3) Environmental system dispatch: system dispatch based on relative environmental costs, as well as monetary cost, which might include dispatching new generation resources on the basis of their ability to displace a more polluting existing plant.

Utility Issues in Bidding

Three issues concerning utility participation or purchase through bidding have recently generated controversy: 1) the treatment of repowered plants in bidding; 2) the impact of power purchase commitments on utility credit rating and cost of capital; and 3) the need for incentives for utilities to acquire third-party resources to meet load generally, and demand side purchases in particular.

Utilities may choose a repowered plant as the benchmark or "avoided" unit against which all bids are measured or the utility may bid a fully depreciated plant in a solicitation in its own or another utility's RFP. In either case, the utility repowered unit is likely to be cheaper than a "greenfield" plant.

Independent power producers expressed concern about bidding against repowered units unless the true costs of a repowered plant were taken into account. For example, bidders insisted that lower efficiencies or reliability of such plants be considered and that full life-cycle capital and operating costs should be taken into account. Bidders also recommended that third parties be allowed to bid to repower a utility asset or to bid on fully depreciated assets such as plant, site, and interconnections to assure that the ratepayers receive full value for these long-lived assets.

In recent years, some utilities, prompted by reports from utility credit rating agencies, have proposed either that their avoided cost be lowered or that a premium be considered to compensate for the alleged negative effect of third-party purchases on utility cost of capital. While no rating agency has downgraded a utility's credit on this basis to date, the issue is being widely discussed before state commissions and the Congress. The rating agencies acknowledge that the terms and conditions of individual contracts, the utility's skill in administering them, and regulatory treatment of contracts can all affect its impact on a purchasing utility, making any generic analysis, and general application in competitive procurement, highly speculative.

Moreover, bidders note that equal consideration should be given to power purchases which strengthen a utility's credit standing by reducing fuel risk, diversifying supply points and shifting risk from ratepayers by other means.

A related issue concerns financial incentives for utilities to purchase supply or demand resources. Since all resource purchases are treated as expense items which may be recovered from ratepayers but upon which utilities earn no return, some argue that utilities lack profit incentives to rely on third parties.

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Nationwide, 28 state commissions are considering financial incentives for utilities to pursue demand-side management programs. Eight commissions are examining incentives for supply-side purchases.

While more than half of the bidders surveyed support supply-side incentives, many stated that minimizing cost to ratepayers through least-cost purchasing should be incentive enough for utilities.

GUIDELINES FOR COMPETITIVE PROCUREMENT SYSTEMS

The following recommendations represent a synthesis of the concerns of bidders, utilities, and state regulators expressed in the NIEP survey.

Integrated Review of Resource Options

While formal bidding, negotiated contracts outside bidding, and competitive negotiation all have a place in a competitive procurement system, their common denominator should be integrated resource planning to determine long-term resource needs, coupled with a contract review process which insures that all selected resources — whether third-party supply, conservation and DSM, utility construction, or repowered facilities — conform to the plan and to rules of fair competition. Developers should view these processes as insurance for the integrity of the power market in a given state. Such a system would hold utilities accountable to state commissions, developers and the public for their resource acquisition decisions in the context of available alternatives.

To promote a competitive environment for resource acquisition, an integrated resource planning and contract approval process should:

1) Allow public participation in the development of competitive bidding or negotiation programs conducted pursuant to an integrated resource plan;

2) Require utilities in all cases to submit sealed, fixed price bids. Utilities should be bound by their bid price if costs exceed projections, but also be permitted to retain any difference between the bid price and eventual cost in the event of lower than anticipated costs;

3) Make the methodology for determining scoring, ranking, and pricing public;

4) Provide for commission pre-approval of contracts for new generating facilities and require that utility-built facilities be subjected to the same regulatory review imposed upon third-party facilities; and,

5) Permit negotiation and contracting outside bidding or negotiation when consistent with the integrated resource plan's objectives of promoting renewable technologies, innovative project design, DSM, or other resource options which are not easily accommodated in the formal bidding or negotiation process.

Competitive Negotiation

Many bidders responding to the survey preferred "competitive negotiation" to either "pure bidding" or "pure negotiation." Hybrid systems, such as competitive negotiation, retain some of the objective elements of pure bidding without its perceived rigidity and over-emphasis on price. In competitive negotiation, bidding criteria become a screen to qualify projects for negotiation. The negotiation is competitive because the number of megawatts offered by qualified projects may greatly exceed the number requested, and utilities then select among the best of these projects.

With elements of both bidding and negotiation, competitive negotiation has been shown in some instances to produce a better over-all bidding procedure. A 1990 report of the Massachusetts Electric Company found that non-price terms and conditions in negotiated contracts offered, "...additional value...versus bid contracts." The same study found, contrary to conventional wisdom, no significant price difference between resources acquired through negotiation and bidding.

NIEP recommends competitive negotiation as an alternative to price-driven bidding for the following reasons:

1) Since the terms are not fixed, it permits developers to be more creative and tailor projects to the particular needs of the utility in terms of timing, siting, fuel supply, design, performance, security and contract termination provisions, among others, once they reach the negotiating stage;

2) It removes the potential incentive for some bidders to offer unrealistic projects which will do well evaluated against price dominated bidding criteria, but may never get built; and,

3) It offers a more rational way to screen qualified potential suppliers. Utilities generally acquire many goods and services, including fuel supply, engineering, design and construction services, by negotiating with pre-qualified suppliers, as in competitive negotiations.

Contracting Outside Bidding

To permit utilities to sign up capacity which may be unsuited for bidding, yet maintain accountability and integrity in the competition, NIEP recommends that:

1) With approval from their commissions, utilities should establish guidelines for negotiating and contracting outside bidding. Guidelines should describe the kinds of projects eligible for contracts outside bidding and a method for keeping the pricing and terms and conditions of these contracts in line with either avoided cost or other contracts obtained through formal bidding or other competitive procedures;

2) The burden of persuasion on the merits of a project should lie with the developer; and,

3) The state commission, in the process for approving contracts awarded outside bidding, should review the impact of the contracting process on the bidding system as a whole and insure that the fairness of the competitive procurement system in the state is maintained.

Bidding Into Public Power RFPs

Many public power entities are now using competitive bidding as a method to meet resource needs. Bidders have expressed concern that: 1) some public power entities view RFPs as a way to gain bargaining leverage over their traditional utility suppliers, rather than a serious means of acquiring new resources; 2) the solicitations of some public power entities are less "sophisticated" than those of investor-owned utilities; and, 3) no impartial entity such as a state regulator has the authority to oversee the bidding procedures of public power RFPs and provide an avenue of appeal if mistakes are made.

In view of these concerns, NIEP recommends that:

1) FERC should delegate to the states what authority it has to oversee bidding by public power entities not subject to state utility regulation;

2) Where state law permits, state commissions should exercise authority derived from integrated resource planning, siting procedures, and "convenience and necessity" certification processes to exercise more control over public power bidding programs; and,

3) State public utility commissions should be able to choose to arbitrate disputes between bidders and public power entities.

Treatment of Regulatory Compliance Costs

The occurrence of unforeseen, "post contract" regulatory compliance costs can present major problems for fixed-price contracts. The fact that utility projects can usually pass through these costs (subject to commission review) grants a competitive advantage to a utility's "build" option. However, contract adjustments for third-party suppliers should not be routinely given because of the potential for abuse. This issue demands a level of compromise from both buyer and seller, with strict oversight by the state commission.

NIEP recommends that where a cost increase due to unforeseen changes in regulation causes an economic hardship for a developer, regulators should allow contract amendments that permit either:

1) The developer to fully or partially pass unforeseeable costs through; or,

2) The utility and developer to renegotiate contract price.

However, this cannot be a free ride for developers. The developer must bear the burden of demonstrating that:

1) The changes were unforeseen;

2) The cost increase was large enough to threaten the viability of the project; and

3) The proposed solution meets a "just and reasonable" standard.

Treatment of Environmental Externalities

Respondents generally agreed that environmental externalities should be included in the selection criteria of the bidding process. Including externalities in bidding programs can create a level playing field for clean resources and gives bidders incentives to minimize the environmental impacts and total societal costs of their projects. To implement this aim, NIEP makes recommendations in the areas below:

1) Any externality policy must be applied equally to utility and non-utility supply and demand resources. There is a danger that state commissions, in encouraging utilities to undertake their own programs to increase energy efficiency, may close off competition from more cost effective non-utility supply and demand-side providers.

2) While the number of identified externalities and the methods for measuring them differ from state to state, NIEP recommends that commissions review the checklist of externalities to ascertain that they include the societal costs of a broad range of fuels and technologies and are not unduly influenced simply by ease of measurement.

3) The determination of what environmental impacts are to be included and how they are to be measured should be made in a public process, with an opportunity for all potential suppliers and other affected persons to participate.

4) Utilities and state commissions should consider whether the application of externality analysis to project selection should be accompanied by environmental dispatch of the system. This may be a way to deal with the anomaly that externality policies only evaluate the environmental costs of new plants, not the total societal costs of decisions to continue to run older existing plants which may be less efficient and more polluting.

Utilities and commissions must develop fair and consistent methods of comparing the costs of a repowered plant with other resource options.

5) For competitive power markets to flourish, sulfur dioxide (SO_2) emission allowance markets created under the Clean Air Act Amendments of 1990 must flourish as well. State regulators should recognize that non-utility generators, because their existing plants are clean and do not therefore offer opportunities to acquire allowances through over-compliance, will have to rely on the allowance market for new plants. State regulators should strive to assure that bidders who need allowances are afforded a reasonable, fair, and timely opportunity to obtain them.

6) The allowance requirement should not be allowed to tilt competition in favor of "build" over "buy" options. For the benchmark or avoided utility plant, the cost of allowances should not be zero; they should be priced at market. For bidders who cannot acquire allowances, states may also want to consider whether allowances should be held "in trust" for winning bidders or auctioning allowances held by host utilities to bidders.

Treatment of Repowered Plants in Bidding

Utilities and commissions must develop fair and consistent methods of comparing the costs of a repowered plant with other resource options. Developing a measure of "fair market value" for repowered plants to use in these comparisons was widely supported by bidders.

NIEP recommends that state commissions adopt the following treatment of repowered plants in competitive procurement:

1) Utilities who wish to use a repowered plant should be required to submit a sealed bid and be held to its bid price should it be selected.

2) The cost of repowering should be adjusted to reflect the shorter expected lifetime of repowered plants, and include potential penalties for decreased reliability, increased maintenance cost, lower efficiency, and greater environmental impacts versus a new plant.

3) State commissions should have authority to approve in advance the spinoff or sale of fully depreciated repowered units to a utility's separate affiliate, as long as ratepayers receive the benefits of the sale to which they are entitled at market pricing.

Impact of Purchased Power on Utility Finances

Some utilities have asked their state regulators to consider the alleged negative effect which third-party power purchases may have on utility cost of capital. They also state that independent power producers may gain an unfair competitive advantage by transferring certain regulatory, market, and operating risks to their utility purchasers.

For this concern to have merit, two unlikely events must occur simultaneously: 1) the utility must either lack or fail to exercise its leverage in contract negotiations to account for the perceived risk in contract price, terms or conditions; and 2) the state commission, with authority over the purchasing utility, must be unwilling to intervene in a procurement process which supposedly puts the utility and its ratepayers at a disadvantage.

Nevertheless, it is likely that many commissions will confront this issue. As they do so, NIEP recommends that state regulators follow the guidelines below:

1) Regulators should fairly evaluate the impact of contract power obligations against the potential impact on the utility cost of capital of the alternative, namely, the utility building the plant itself.

2) Regulators should not look at the impact of purchase obligations on utility credit rating in a vacuum. They must also consider the credit impact of utility decisions to build rather than buy. For example, in the 1980s, the surest way for a utility to improve or maintain its credit rating was to defer or disavow any new plant construction.

3) Regulators should consider how performance criteria and other contractual guarantees, including security deposits and liquidated damage provisions, mitigate any financial impact of the utility's contractual commitments.

4) In evaluating the impact on credit ratings, regulators should treat equally all contracts involving long-term commitments by the purchasing utility, such as assessing the potential financial effect of purchases from another utility's system in the same way as power purchases from a stand-alone generator.

5) Regulators should recognize enhanced reliability from diversified and dispersed fuel and power supply sources.

Incentives for Utility Purchase of Supply and DSM Resources

Since purchases of power from cogeneration, renewable resources, Demand-Side Management (DSM) providers or other non-utility sources add nothing to utility profits, some utility executives and state regulators have proposed that utilities receive financial incentives for purchasing non-utility resources. Over the past several years, a number of commissions have instituted financial incentives for utilities to pursue conservation and demand-side management programs although to date only one has adopted an incentive program for supply purchases.

NIEP opposes financial incentives to encourage utilities to purchase supply resources, however, competitive procurement should be encouraged as an option. Utilities have a public service obligation to acquire the most cost-effective resources regardless of whether they make contributions to their ratebase and, therefore, their shareholders. Parallel financial treatment for conservation may make more sense for regulators to adopt because under current rate-making, unlike purchased power, successful conservation programs diminish kilowatt-hour (kWh) sales and, in concert with the lag involved in recovering program costs, may lead to harmful revenue erosion for the utility.

If incentives for utilities to undertake demand-side management programs or purchase power are implemented, strong regulatory checks are necessary to ensure that:

- Cost estimates for avoided and actual resources are accurate;
- The incentive payment is directly tied to performance of the utility managing the purchase;
- Utilities are encouraged to invest in the most efficient resource (taking into account all alternatives);
- Utilities are penalized for poor performance in managing contracts; and,
- Utilities should not ignore the existence of third-party demand-side management providers who may be more cost-effective than utility providers.

CHAPTER I — INTRODUCTION

What was intended as evolutionary change in the electric utility industry with the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) started a revolution, redefining the way we look at electricity generation. The success of PURPA in attracting new suppliers into generation markets challenged the fundamental economic assumptions about generation that guided regulation for decades. The emergence of new suppliers of generation, both Qualifying Facilities (QFs) and non-QF independent power plants (IPPs), has transformed the acquisition of power supply through the adoption of competitive power procurement systems.

This study is the third in a series of reports by the National Independent Energy Producers (NIEP) chronicling the emergence of the competitive generation market. The first was published in 1987 and the second in 1990 (using data collected in 1989).

Competitive bidding for electric power has grown tremendously since it was first introduced in Maine in 1984. In the intervening seven years, 67 competitive Requests for Proposal (RFPs) have been issued by 49 utilities and 3 government agencies. In that time, utilities have requested nearly 20,000 megawatts through bidding. All of this is occurring in an industry classified by most observers until very recently as a vertically integrated "natural monopoly."

Bidding's importance as evidence of the fading monopoly characteristics in generation markets is indisputable. Much more controversial is the issue of how well bidding accomplishes its intentions — that is, giving utilities the opportunity to purchase reliable, lower cost power supplies from among a variety of suppliers. This question is the focus of this latest inquiry into bidding by NIEP. Unlike the previous two reports which focused on the rules governing bidding, this study focuses on the actual practice of bidding from the perspective of bidders. After all is said and done, one critical test of how successful bidding is as a method of procuring power supply is whether bidders will continue to come to the market offering projects that stand a good chance of coming on-line, on-time and at reasonable costs. More importantly, the success of bidding will be judged by how much capacity comes on-line and serves load reliably throughout its life.

In its short history, bidding for power contracts has expanded faster than its initiators could have anticipated. Competitive bidding for generation resources was born in Maine in 1984. The Maine Public Utilities Commission set avoided-costs for Central Maine Power (CMP) based on an "avoided" nuclear unit. At this price, CMP was flooded with contract requests from QFs. CMP proposed bidding to its commission as a way to rationally allocate that capacity among the potential suppliers to bring the power needed on-line at the lowest cost. Maine and its utilities, in a sense reacting to an extraordinary set of circumstances, hit upon bidding. Since then, Maine has consistently been a leader in competitive power markets.

In the mid to late 1980s, bidding was concentrated in New England and the rest of the Northeast. In 1986, unlike its neighbors, Connecticut adopted a very different approach to bidding — the Connecticut Department of Public Utility Control, the state regulatory authority, issued a solicitation for 500 MW. The current economic slowdown has stifled most new RFPs in this area, although there is some modest bidding activity expected in New England, New York and New Jersey.

The next major bidding lab to emerge was Virginia. Throughout the mid and late 1980s, Virginia's economy and population grew at a healthy clip, stimulating growth in demand for electricity. Beginning in 1986 and over the next four years, the state's dominant investor-owned utility, Virginia Power (VEPCO), sought to procure over 4,100 megawatts of new capacity through bidding without formal involvement by the Virginia State Corporation Commission. Although that activity has tapered off for the moment, Virginia has been the single largest bidding market, so large in fact, that it had, for several years, skewed any analysis of bidding towards the VEPCO experience. Many of the winning projects in Virginia (as well as in Maine and Connecticut) are now entering the "mature" development stage, and some have already made a successful transition from winning bid to operating powerplant.

From there, bidding has spread throughout the country in a number of different ways. In some states, utilities such as Virginia Power undertook bidding without state regulatory commission rules on bidding programs in place. Some commissions (such as New Jersey, Delaware and Virginia) subsequently issued, or are in the process of, developing guidelines, rules or decisions governing future RFPs. Other states have taken no formal action on bidding despite RFP activity by jurisdictional utilities (such as Florida). By contrast, a number of states, such as New York, Washington, California, Oregon and Ohio, issued rules in advance of bidding. Several states with comprehensive rules on bidding have yet to have an opportunity to have them tested in RFPs. California's investor-owned utilities have not needed incremental capacity since the California Public Utilities Commission adopted its bidding rules, so California's rules remain untested, as do the Massachusetts Department of Public Utilities' new bidding rules adopted in 1990 (although Massachusetts utilities used bidding extensively under the previous rules adopted in 1986).

Another interesting development has been the spread of bidding among public power entities, which generally are not subject to direct regulation by public utility commissions. A total of 17 government agencies, rural electric cooperatives and municipal and other "public" utilities have issued RFPs. These entities vary a great deal in the size of their loads and the megawatts requested through bidding. Recently, the Rural Electrification Administration, which administers low-interest loans to the nation's rural electric cooperatives (RECs), began to require that RECs needing capacity must bid it.

In summary, bidding, in its inception in Maine in 1984, was viewed as a way to ration or allocate capacity to an over-supply of QFs which had presented themselves to Central Maine Power with its high avoided-costs. In the mid to late 1980s, bidding then emerged to entice new suppliers into the market in capacity-hungry regions such as the Northeast and the Middle Atlantic states.

In the early 1990s, bidding exists in nearly every part of the country that anticipates a need for new generating capacity. Also, with the rapid development of least-cost or integrated resource planning, it is being contemplated in states with longer planning horizons, where there are no immediate needs for new power supply. Finally, regulators are beginning to view bidding as a benchmark against which utilities will have to show that their resource plans will yield the best results for ratepayers. It is safe to conclude, as we did in our 1990 study, that bidding has emerged as one of the dominant methods of procuring new supplies of electricity.

If there is one thing that can be said about bidding as practiced since 1984, it is that there exists no single way to do it. Investor-owned utilities and public power entities (including municipal utilities, power marketing agencies and rural electric co-ops) have issued RFPs. RFPs have been conducted under formal state rules, state guidelines and solely at the utility's own initiative. While some RFPs solicit bids from all supply and demand sources, others restrict bids to QFs only. Some utilities have issued only one RFP, while others have issued three or four. The way bidders approach bidding also constantly changes as they gain more and more experience in bidding in the many different types of RFPs issued by these entities under a variety of circumstances.

Moreover, a number of solicitations have completed the cycle from issuing the RFP, selecting winners, signing power purchase agreements, to financing, construction and finally commencing commercial operation. As of February 1991, a survey of 172 projects selected through bidding showed that over 85 percent of those projects, accounting for 9,297.8 megawatts, were in development, under construction or on-line. By contrast, 13.5 percent of those projects, accounting for 1,453.2 megawatts had been canceled. The majority of the 26 projects canceled failed from an inability to: 1) sign a power purchase contract, 2) post a security deposit, 3) obtain a cogeneration host or 4) arrange wheeling.[1] However, most of those projects failed early enough so that they did not interrupt the utility's power supply plans. Moreover, utilities and commissions expect some projects to fail and build a failure rate into their RFPs. For example, the Massachusetts DPU bidding rules permit utilities to negotiate with 130% of the megawatts requested in the RFP, and Virginia Power estimated a 20 percent failure rate in its bidding program.

Finally, it is important to note that bidding is only one element of the quickly changing landscape of the utility industry. While utilities continue to plan for and obtain capacity by constructing it themselves, they also are increasingly looking to meet capacity needs by purchasing from other utilities under firm contracts; buying from independents through bidding, negotiation or standard offer; or slowing load growth through demand-side management and conservation. In fact, independent generation, contracted for through negotiation, bidding or standard offer, accounted for 50 percent of the new capacity brought on-line in the US in 1989 and 1990.[2]

The growth of the independent generation sector and other economic and competitive developments has sparked serious examination of the future of the generation sector. Discussions of industry structure in the national legislative debate over amending the Public Utility Holding Company Act (PUHCA) has focused attention and scrutiny on issues such as bidding, power purchases and competition in general. Policymakers in the states and at the federal level are not only assessing the value of competition in power markets, but are also, in some areas such as Ohio and Illinois, seeking to expand its practice.

In addition, a number of other regulatory and legislative developments potentially affect and shape competitive procurement systems. One of the major trends in the electricity industry is increasing environmental concern at the state and federal levels. Among the most prominent developments are: 1) the establishment of sulfur dioxide (SO_2) emission allowance trading provisions of the Clean Air Act Amendments of 1990, and 2) the requirement by an ever increasing number of states to include environmental externalities in generation resource procurement. Another issue receiving notice from regulators and legislators is, for example, whether to give financial incentives for utilities to purchase supply and demand resources. These developments each add a new wrinkle of complexity to the already complex competitive framework.

Since so much attention is currently focused on competition in generation markets, and much of the competitive activity is concentrated on bidding, we have undertaken to assess the current state of bidding by examining the entire process of bidding through the eyes of bidders. Moreover, we will recommend policies and guidelines which we believe will help preserve competitive, viable power markets and make competition a more effective tool for procuring generating capacity.

What Makes This Study Different?

NIEP believes it is important for participants in competitive generation to monitor the evolution of bidding, to point out its pitfalls and its successes, and to offer recommendations to improve the efficiency of competition and competitive power markets. As we noted earlier, this is NIEP's third study tracking the progress of bidding. We wanted to look at the full cycle of bidding, not just at its rules, but how it is practiced and the final results. We want to try to understand the positive and negative aspects of bidding, now that states and utilities have some substantial experience in conducting bidding and assessing its results. By examining bidding in the context of other options to procure power, we also hope to arrive at conclusions about issues emerging in bidding and recommend policies which we believe can improve the competitive procurement of generating capacity.

What makes this study different from the prior NIEP studies on bidding? In our 1990 report, *Bidding For Power: The Emergence of Competition in the Market for New Electric Generation*, we presented a snapshot of bidding, its status in every state, the results of each RFP issued to date, and comprehensive guidelines addressing many of the policy issues which emerged in bidding rules and programs. Now, publications such as *Robertson's Current Competition* provide frequent updates on bidding activity and results — in this study, we will only summarize that data. Instead, in this report, we will analyze policies and issues emerging from the practice of competitive bidding.

Moreover, we have focused on bidding in five key states which reflect geographic diversity, different approaches to, and different experiences with, bidding: New Jersey, Virginia, Florida, California and Washington. However, this report is not a case study of each state. Instead, we sent questionnaires not only to commissions and utilities who have hosted bids in those states, but also to companies who have bid in those states. Nevertheless, we did not ask them to limit their responses to their experience in those states. Our overall response rate for the surveys we sent out to bidders, states and utilities was very good — 62 percent (33 out of 53). We have incorporated additional relevant information from state bidding rules and practices in "non-target" states and from other recent materials on some of the specific issues we examined.

The questions asked of respondents were designed to extract their views on policy issues emerging in bidding as practiced today. Some of these issues are not currently being addressed in bidding, but have surfaced as a result of bidding or other changes in the industry. The survey questions asked of bidders, commissions and utilities can be grouped in three ways:

- How do bidders perceive bidding?
- How do commissions treat the design and results of bidding, particularly with respect to the handling of environmentally-related costs?

- What impact does bidding have on the utilities who purchase power through it?

This study is unique because it offers the perspective of developers who have participated in a number of bids and emerged as both winners and losers. Attitudes about bidding will ultimately affect how successful bidding, in particular, and competition, in general, is in meeting future capacity needs. The study attempts to present those bidders' recommendations for addressing newly developing issues in bidding. What we hope emerges from this study is not an unqualified endorsement of bidding nor a universal rejection of bidding, but rather an analysis of criticisms of bidding, with some suggestions on how to improve the competitive process to yield better results overall. Finally, we offer a hybrid model for competitive negotiation which attempts to meld the flexibility of negotiation with the accountability of bidding into a comprehensive framework of beneficial competition.

Organization of the Study

The report is organized as follows:

Chapter II — Current Status of Bidding in the United States

Chapter III — How Bidders View Bidding
- Contracting outside bidding.
- Bidding in public power solicitations.
- RFP design issues.

Chapter IV — Commission Treatment of Environmental Issues in Bidding
- Treatment of changes in regulatory compliance costs.
- Treatment of environmental externalities.

Chapter V — Impact of Bidding on Utilities
- Bidding repowered plants.
- Financial issues for utilities.

Chapter VI — Guidelines and Recommendations for Competitive Procurement

NOTES

1. *Robertson's Current Competition*, February 1991, Volume 2, Number 4, page 13

2. Utility Data Institute, "Independents Built More Capacity than Electric Utilities in 1990," *Electric Utility Week*, January 7, 1991, pages 9 and 10.

CHAPTER II —
CURRENT STATUS OF BIDDING IN THE UNITED STATES[1]

Since 1984, 36 states, more than two-thirds of the states, have adopted, are developing, would consider, or permit competitive procurement procedures to determine how their future electric generation needs will be met.[2] (See **Table One.**) The great majority of this interest has developed since 1987.

TABLE ONE

SUMMARY OF STATE COMMISSION ACTIVITY IN THE U.S.

Number of States*	Action
11	Have Established Bidding Rule
8	Allow Bidding, no Rule
6	Developing a Bid Rule
3	Currently Reviewing Bidding
8	Would Consider Bidding in Future
13	No Interest in Bidding
2	Have Rejected the Use of Bidding
51	

* Includes the District of Columbia

More than two-thirds of the states, have adopted, are developing, would consider, or permit competitive procurement procedures.

Summary of Bidding Activity

There are 28 states that: 1) have adopted bidding; 2) permit jurisdictional utilities to hold bids; 3) are developing a bidding program; or 4) are reviewing the use of bidding in their state.

A total of 67 RFPs have been issued by 51 utilities to date. Of these 67 RFPs, 31 were issued subject to state bidding rules by 24 utilities in 8 states. (See **Table Two.**) In 24 states, RFPs have been issued either outside state rules or by non-jurisdictional utilities.

TABLE TWO

NUMBER OF UTILITIES AND GOVERNMENT AGENCIES ISSUING RFPs (AS OF MAY 1, 1991)

67 RFPs Issued by 52 Utilities and Government Agencies

Type of Utility	Number
Investor-Owned	34
Public Power	7
Rural Electric Co-ops	7
Government Agencies	3
	51

Bidding Initiated by State Regulatory Commissions

Eleven state regulatory commissions (California, Colorado, Connecticut, Maine, Massachusetts, New Jersey, New York, Ohio, Oregon, Virginia and Washington) have developed and implemented bidding programs. California's bidding rule will affect three utilities when it is used, most likely by early 1992.

Bidding in other states varies. Four states (Iowa, Kansas, Louisiana and Mississippi) are considering adopting bidding procedures but may restrict it to demand-side management and conservation activities, since they have no immediate need for supply-side capacity. Four states (Arizona, Minnesota, South Carolina and Utah) foresee consideration of bidding as a part of their state least-cost or integrated resource planning. For example, the Arizona Corporation Commission proposed bidding in their least-cost planning docket (LCP), and final ruling in that proceeding is due this summer. Montana, which permits bidding although no Montana utility has yet issued an RFP, initiated a docket which includes consideration of bidding rules in the context of least-cost planning. By contrast, in Florida, the two largest investor-owned utilities (Florida Power and Florida Power and Light) have issued RFPs without commission rules, and the state has no plans to adopt a formal bidding rule.

Bidding Programs Initiated by Investor-Owned Utilities

Twelve investor-owned utilities in 10 states have initiated bidding programs without formal advanced approval by their public service commissions. (**See Table Three.**)

TABLE THREE

SUMMARY OF INVESTOR-OWNED UTILITIES WHICH HAVE ISSUED RFPs IN STATES WITH NO FORMAL BIDDING RULES

State	Utility	# of RFPs
Delaware/Maryland	Delmarva Power & Light	1
Florida	Florida Power Corp.	1
	Florida Power & Light	1
Hawaii	Hawaiian Electric Company	1
Indiana	Public Service of Indiana	1
Massachusetts	New England Power*	1
Nevada	Sierra Pacific	2
New Hampshire	Public Service Company of New Hampshire	1
	UNITIL	2
Vermont	Central Vermont Public Service	1
	Green Mountain Power	1
Virginia	Virginia Power**	4
Total Number of RFPs		17

* Because it is part of a multistate holding company (New England Electric System), NEP is exempt from the Massachusetts' DPU bidding rules.

** RFP issued under informal bidding guidelines, however, in 1990, the Virginia State Corporation Commission issued formal bidding rules.

Although in these situations, state commissions do not directly review or approve the solicitations, they have an opportunity to review bidding after-the-fact. These state commissions often must approve contracts in utility cost recovery proceedings or in hearings on petitions for Certificates of Convenience and Necessity with respect to proposed new facilities.

The Future of Bidding Activity

Nine states (California, Delaware, Illinois, New Hampshire, Maryland, Michigan, Oregon, Pennsylvania and Vermont) are in the process of developing, modifying or approving bidding proposals. Seven states (Arizona, Iowa, Kansas, Minnesota, Mississippi, Missouri, Utah) and the District of Columbia have expressed their intention to consider bidding at some time in the future. Of those eight, six may include bidding as an option in their least-cost, integrated resource or demand-side management planning processes.

Bidding Programs Initiated by Municipal Utilities, Public Power Systems, Rural Electric Cooperatives and Government Entities

Interest in bidding by public power utilities, rural electric cooperatives and government agencies has grown over the last two years. The following have held bid solicitations:

- Three municipal utilities have issued RFPs for 2,346 MW (Los Angeles Department of Water & Power, Sacramento Municipal Utility District, and Orlando Utilities Commission)
- Four public power agencies have issued RFPs for 1,530 MW (Northern California Power Agency, Indiana Municipal Power Agency, Eastern Municipal Power Agency, and AMP-Ohio)
- Seven rural electric cooperatives have issued RFPs for 1946 MW (Oglethorpe Power Corp, Seminole Electric Co-op, Sam Rayburn Electric Co-op, North East Texas Electric Co-op, Brazos Electric Co-op, East Kentucky Electric Co-op, and Alabama Electric Co-op)

- Three government entities have issued RFPs for 850+ MW (Bonneville Power Administration, Vermont Department of Public Service (no cap) and the Connecticut Department of Public Utility Control)

The 67 competitive bid solicitations issued as of May 1, 1991, represent a total of over 19,273 megawatts of requested capacity.

Capacity Subject to Bidding

The 67 competitive bid solicitations issued as of May 1, 1991, represent a total of over 19,273 megawatts of requested supply-side capacity. Not included in the number of MWs requested are RFPs issued by Maine Public Service Company and Vermont Department of Public Service where the number of megawatts was not specified. (See **Table Four**.)

TABLE FOUR

RESULTS OF RFPs ISSUED SINCE 1984
As of May 1, 1991

State	Requesting Utility	MW Requested	MW Bid	MW Awarded
AL	Alabama Electric Co-op	140	718	Rejected All Bids
CA	LA Dept. of Water and Power	600	4135	Not Awarded Yet
CA	Northern California Power Agency	40-330	3580	Not Awarded Yet
CA	Sacramento Municipal Utility District	1406	14665	Not Awarded Yet
CT	Connecticut Light & Power (CDPUC)	500	800	552
DE/MD	Delmarva Power	100	833	48
FL	Florida Power Corp.	400	1026	559
FL	Florida Power and Light	800	10793	646
FL	Orlando Utilities Commission	440	1276	Rejected All Bids
FL	Seminole Electric Cooperative - 1st	440	1989	440
FL	Seminole Electric Cooperative - 2nd	660	5479	Not Awarded Yet
GA	Oglethorpe Power	700	7261	300
HI	Hawaiian Electric Company - 1st	146	618	326
HI	Hawaiian Electric Company - 2nd	500	2500	500
IN	Indiana Municipal Power Agency	120-160	750	Rejected All Bids
IN	Public Service of Indiana	1300	1739	640
KY	East Kentucky Power Co-op	400	4601	Not Awarded Yet
ME	Maine Public Service	Open Ended	60	Not Awarded Yet
ME	Central Maine Power - 1984	100	462	150
ME	Central Maine Power - 1984	100	314	153.5
ME	Central Maine Power - 1987	100	4235.6	128
ME	Central Maine Power - 1987	100	907.6	Suspended
ME	Central Maine Power - 1989	100-700	2810	63.1
ME	Bangor Hydro	60	1576	Suspended
MA	Boston Edison - 1987	200	1847.8	344.1
MA	Boston Edison - 1989	200	2827	200

Table Four
Continued

State	Requesting Utility	MW Requested	MW Bid	MW Awarded
MA	Cambridge Electric Company - 1988	33	131	33
MA	Cambridge Electric Company - 1990	28	556	23
MA	Commonwealth Electric - 1988	76	914	102.5
MA	Commonwealth Electric - 1990	88	920	93.5
MA	Eastern Edison - 1988	30	179	40
MA	Eastern Edison - 1989	30	337	30
MA	Fitchburg Electric Company	11.7	455.4	13.5
MA	Nantucket Electric Company	4	0	N/A
MA	Western Massachusetts Elec. Co.	54	382	74
MA	New England Power	200	4729.4	205
NV	Sierra Pacific Power - 1988	125	3200	238
NV	Sierra Pacific Power - 1990	200	2560	107.4
NH	Public Service Company of NH	50	467.9	Rejected All Bids
NH	UNITIL	15-40	250	Cancelled
NJ	Jersey Central Power & Light	270	768	217
NJ	Public Service Electric & Gas	200	701	210.3
NY	Consolidated Edison Company	200	3096	203.7
NY	Long Island Lighting Company - 1990	150	1770	Not Awarded Yet
NY	Niagara Mohawk Power Company	350	7278	405
NY	New York State Electric & Gas	100	585	Not Yet Awarded
NY/NJ	Orange & Rockland Utilities/ Rockland Electric	200	1396	195
NY	Rochester Gas & Electric	70	59	Not Awarded Yet
NC	Eastern Municipal Power Agency	240	396	75.8
OH	American Municipal Power	20-100	1075	275
OR	Bonneville Power Administration - 1990	50	100	46
TX	Brazos Electric Cooperative	206	314 - 684	Rejected All Bids
TX	Sam Rayburn Electric Cooperative	25+	115.8 - 133.8	97.6
TX	Northeast Texas Electric Cooperative	75	1000+	Not Awarded Yet
VT	Central Vermont Public Service	50	660	53
VT	Green Mountain Power Company	115-240	806	60
VT	Vermont Dept. of Public Service	No Cap	1810	Not Awarded Yet
VA	Virginia Power - 1986	1000	5000	1181
VA	Virginia Power - 1988	1750	14653	2088
VA	Virginia Power - 1989	300	2139	Rejected All Bids
VA	Virginia Power - 1989	1100	11600	442
WA	Puget Sound Power & Light	100	1338.7	136.6

RFPs Elicit More Capacity Than Requested

ince 1984, there have been 1,344 supply-side projects bid representing over 104,201 megawatts of capacity. In the 42 solicitations where the winners have been selected, there were 315 projects, representing 11,946 megawatts of capacity awarded. (**See Table Four.**) The capacity bid in these RFPs ranged from 1.5 to 42 times the amount of power requested, with the average response for an RFP being 10 times the capacity sought.[3] For these RFPs, in only one case did the amount of power elicited fall below the amount of power requested. This occurred in Nantucket Power's 1988 request for four MW of capacity, where no bids were received. In the 13 RFPs where the filing period has closed but winners have not yet been selected, 321 projects representing 37,921 megawatts have been bid.

fter evaluating proposals, capacity was not awarded in nine solicitations. (**See Table Five.**)

TABLE FIVE

RFPs WHERE NO CAPACITY WAS AWARDED

Utility	Action	Reason
Alabama Electric Co-op	All Bids Rejected	Repowering their own plant
Brazos Electric Co-op	All Bids Rejected	Building their own plant
Indiana Municipal Power Agency	All Bids Rejected	Building their own plant
Orlando Utilities Commission	All Bids Rejected	Building their own plant
Public Service Company of New Hampshire	All Bids Rejected	Pending merger with Northeast Utilities
Virginia Power (3rd RFP in 1988)	All Bids Rejected	Building their own plant
Bangor Hydroelectric Company	Suspended Solicitation	May refile
UNITIL	Canceled Request	May combine with next RFP
Nantucket Electric Company	Received No Bids	Received no bids

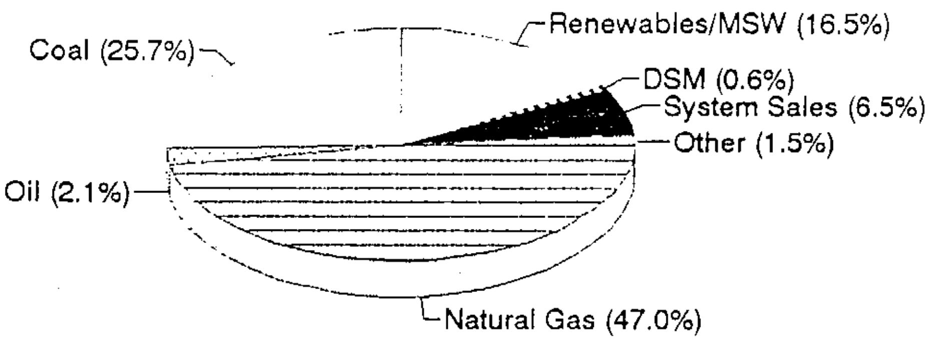
Since 1984, there have been 1,344 supply-side projects bid representing over 104,201 megawatts of capacity.

Bids Reflect a Diversity of Technologies

A wide cross-section of technologies have competed in bid solicitations. However, the vast majority of the winning bids, measured in megawatts, has been natural gas and coal fired projects, either cogeneration or independent power projects which do not qualify under PURPA. Projects using natural gas and coal technologies account for 8,266 MW, or 68 percent of megawatts awarded. Renewable energy projects, including hydro, geothermal, resource recovery, wood, and other biomass, account for 2,106 MW or 16.8 percent of the total megawatts awarded as of May 1, 1991. (See Table Six.)

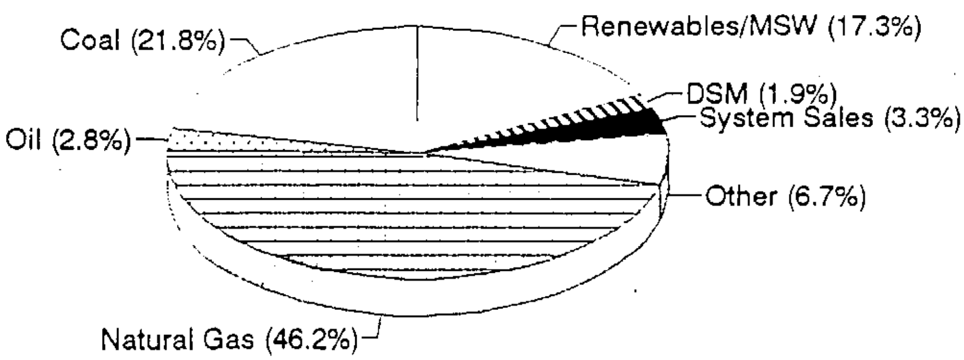
TABLE SIX

FUEL MIX -- PERCENT OF MWs OFFERED
As of May, 1991



Source: Robertson's Current Competition, May 1991

FUEL MIX -- PERCENT OF MWs AWARDED
As of May, 1991



Source: Robertson's Current Competition, May 1991

Few Projects Awarded Contracts Have Suffered Significant Delay or Defaults

· any bidding RFPs have recently matured enough to judge the success of the projects under contract. As of February 1991, 67 projects representing 1,700 MW, and 16 percent of all winning MW capacity have come on-line. Of those 67, 56 projects, approximately 1,420 MW, were on schedule and 11 projects, approximately 280 MW, were delayed an average of nine months. As for projects eventually canceled, 31 projects representing 1,400 MW or 13.5 percent of winning capacity fall into this category. Developers canceled 20 projects and utilities canceled 8 of the 31 failed projects, and in three of these instances, the decision to cancel was mutual.

The causes for project failure vary widely. The top four reasons projects fail are: 1) problems with signing the contract; 2) posting a security deposit; 3) failure to secure a cogeneration host; or, 4) failure to get transmission access. These problems account for 75 percent of all the failed projects. The main reasons surrounding project delay are trouble obtaining air quality permits and public opposition. Unexpectedly, securing a site and financing have caused few project delays.

Two utilities and one government agency have the highest success rates for bidding projects -- Virginia Power, Central Maine Power and Connecticut Department of Public Utility Control. Of the 3,840.5 MW selected in Virginia Power's bids, 656.5 MW are on-line and 678.0 MW are under construction. Central Maine Power, the first utility to use the competitive bidding process for securing new capacity, has 311 MW out of 532.5 MW selected on-line; only 4.5 percent of its winning MW have failed. The Connecticut Department of Public Utilities has 438 MW of capacity on-line with another 33 MW expected on-line soon, representing 85 percent of the MW awarded. To date, none of the winning projects chosen by the Connecticut Department of Public Utilities has failed.

NOTES

1. All information in this chapter comes from *Robertson's Current Competition*, Volume 2, Numbers 4 and 5, February and May, 1991.

2. Includes Bonneville Power Administration under Oregon.

3. Individual RFPs are over-subscribed by an average of ten times the capacity requested. Across all RFPs issued to date, approximately eight times as much capacity has been bid than requested.

CHAPTER III — HOW BIDDERS VIEW BIDDING

In general, bidders' perceptions of bidding can best be characterized as disappointed. Many bidders expressed a general dislike of bidding, with many feeling that bidding systems were unfair. With the increasing cost, time and complexity involved in preparing a bid, this widely expressed dissatisfaction has lead some bidders to state they will no longer bid projects, but rather seek contracts through other means. To date, however, the numbers do not show that more developers are avoiding bidding. The ratio of megawatts bid to megawatts requested has remained steady at about eight to one over the last two years. Developers' complaints about bidding are discussed below.

Overemphasis on Price

In assessing the weights assigned to individual criteria in RFPs, most bidders felt there was still too much emphasis on price, leading to so-called "low ball" or underpriced bids. This was evident in the first Boston Edison solicitation, in which the bids were evaluated almost exclusively on price. In responding to that incident which produced a high percentage of contract failure one bidder noted that "bidding produces only winning bids -- not necessarily successful projects." Such a concentration on price alone may undermine the competitive bidding process:

1) A number of the projects selected ultimately may fail, because some inexperienced bidders greatly understate their price, enabling them to win the bid; and,

2) Bidders believe that the bidding process drives profit margins so low as to make winning a bid an unattractive proposition for the bidders.

Some bidders advocated elimination of price as a criterion as long as the plant was offered at less than the utility's avoided-cost. Under this concept, the competition would be limited to those projects below avoided-cost. The utility would then choose winners based on project feasibility and which developer offered the best terms and conditions.

RFP Design

Respondents provided a number of suggestions with regard to RFP design.

1. Subjective vs. Objective Criteria

Bidders expressed a great deal of concern that subjective criteria were not emphasized enough in bidding, particularly criteria which would help the utility pick projects most likely to actually come on-line. In addition, some bidders voiced doubts whether both the objective and subjective criteria were being applied fairly and consistently in bid evaluation, especially when comparing a "buy" option which is bid to the utility's build proposal.

The subjective criteria in an RFP should include elements which will predict how likely a project will be to come on-line, on schedule and operate reliably over the life of the power contract. For example, in its newly adopted rules governing bidding, the Virginia State Corporation Commission (VSCC) requires utilities to consider in evaluating responses to their RFPs,[1] among other elements, the following:

- Status of project development;
- Demonstrated financial viability of the project and the developer;
- A developer's prior experience in the field;
- System fuel diversity;
- Dispatchability of the project;
- Project location and effect on the transmission grid; and,
- Environmental impacts.

Similarly, the Massachusetts DPU bidding rules also require utilities to incorporate bid criteria relating to project feasibility,[2] including:

- Degree of control of the site;
- Siting and environmental permits needed and obtained;

- Fuel, equipment, engineering and design contracts needed and obtained;
- Degree of financing completed and financial resources of the developer;
- Willingness to provide or presence of security deposits;
- Experience of the project developer; and
- Degree of project completion.

Both sets of rules permit the utilities themselves to assign the actual weights to each of the subjective and objective criteria.

2. Self-Scoring

When asked about their experience, bidders' answers ranged from indifference to mild dislike of self-scoring RFPs. Some felt that self-scoring created opportunities for mischief by both bidders and utilities. Most of the bidders responded that it was best not to rely on self-scoring alone, not only to avoid possible abuse, but also because bidders view self-scoring paradoxically as both vague and rigid. In these responses, we detected a strong undercurrent that many bidders feel some host utilities using self-scoring might not be committed to competition, but were simply going through the motions of bidding to satisfy their regulators. They fear that some utilities might manipulate or influence the RFP design or evaluation process so that the RFP would yield no winning projects. This perception, whether accurate or not, is itself potentially harmful. If bidders believe that utilities using self-scoring do not want to buy power through bidding or that self-scoring is otherwise exploited by utilities or bidders, then the competitive process may be compromised.

3. The Better RFPs

We attempted to ascertain from bidders whether there was anything inherent in types of bidding programs which could distinguish a good RFP from a not so good RFP. For example, bidders perceived no consistent difference in quality between RFPs initiated by utilities and those issued under state bidding rules. Some bidders noted a trade-off where they felt that although contracts awarded through bids issued under state rules might be less likely to be revisited or challenged by the state commissions later, RFPs issued under state rules also tended to be less flexible or more impractical. However, the dominant answer was that some RFPs, whether issued under state rules or initiated by the utility, were just designed better than others.

We asked bidders a series of questions dealing with RFP design. According to the responses, the RFP itself should:

- Contain sufficiently detailed and comprehensive information to enable all bidders to submit an appropriate bid including information about supply block, preferred fuels, timing of need, pricing considerations, operational considerations, preferred or disfavored locations, dispatchability and transmission availability and constraints;

- Have a clearly specified and balanced set of objective and subjective criteria and weightings so that price and non-price factors are given appropriate weight;

- Contain model contracts which are tough on performance requirements but reasonable on "regulatory out" clauses (i.e. those clauses should be lenient enough to be financeable);

- Be mindful of the expense to which bidders must go in preparing a bid;

- Keep information confidential from other bidders and competitors (including the utility itself); and,

- Require utility projects to be held to the same RFP terms and conditions as non-utility suppliers.

Contracting Outside Bidding

Contracting outside of bidding, where it exists, raises an interesting dilemma — on the one hand, a utility should not be denied the opportunity to contract with a potentially beneficial project which could not, for some reason, be accommodated within the bidding framework. On the other hand, if every bidder who wanted to were allowed to deal with the utility outside the bidding or competitive procurement program, this could undermine the competitive process.

When asked about their experience, bidders' answers ranged from indifference to mild dislike of self-scoring RFPs.

According to our survey, most bidders responding have proposed projects outside of bidding. They have done so for a variety of reasons, including: long lead time, high capital cost-projects which the developer thought could not be accommodated within bidding; or projects where the developer may not be able to completely control certain parameters of the project, such as timing. For example, respondents noted that waste-to-energy and hydro project schedules are sometimes controlled, not by the developer, but by governmental entities, making it difficult to comply with bid schedules. Most of the bidders felt there were circumstances under which contracting outside of bidding should be permitted.

By contrast, utilities who responded generally thought that contracting outside bidding should be permitted in only extremely limited circumstances. Utilities surveyed generally did not endorse contracting outside of bidding except for small QFs or energy-only projects. Most utilities would ideally want the maximum number of projects to compare side by side in a formal bidding structure. Utilities also might prefer bidding since it is less open ended than negotiating contracts. With bidding, the utility will within a known time period decide whether, with whom and for how many megawatts it will contract for power, although the bidding process itself may be quite lengthy.

Commission responses were mixed. Some stated they would permit contracts outside bidding under extraordinary circumstances, but not if they would undermine the bidding process. Some commissions permit it by rule (Washington), others under special circumstances (Virginia), while others appear to reject it completely (New Jersey).[3] Finally, a more general survey conducted by NIEP indicated, that in practice, a fair amount of contracting is occurring outside of bidding where bidding is taking place. Twelve active bid states (including states with bidding rules or where utilities have initiated bids) permit such contracts.

Bidders' support for contracting outside bidding, in contrast to the opinions of both the utilities and states, reflects a high degree of discontent with bidding. However, in examining contracting outside bidding, there are important tradeoffs for policymakers to consider. The competitive procurement system should be flexible enough to provide an opportunity for projects which cannot conform themselves to bidding, but will otherwise prove to be advantageous to ratepayers, or provide other societal benefits. However, states and utilities should be concerned about maintaining the fairness of, and accountability within, the procurement process to ensure that the maximum number of potential suppliers compete. Bidding does provide a framework within which to compare, at one time, the relative benefits of all projects.

Bidding Into Public Power RFPs

One of the growth areas in bidding is in public power, including municipal utilities, rural electric cooperatives (RECs), generation and transmission cooperatives, federal and state power marketing agencies. Since 1984, these public power entities have issued 17 RFPs for 2,456 MWs of supply-side capacity. The Rural Electrification Administration, which administers loans to RECs, is now requiring the RECs to bid their incremental capacity needs.

Less than half the bidders responding to the survey had participated in a public power bid. Those who did expressed general unhappiness with the process or outcome of RFPs to which they responded. That may be due in part to the fact that as of the date of the surveys, few public power entities had announced any winners of their RFPs, and even fewer had signed any contracts as a result of bidding. In one case, a public power agency RFP has been open for more than two years. The open-ended nature of some public power bids may be due to changing resource needs, lack of staff or resources to complete a bid or bid evaluation, or lack of structure or authority pushing them to complete a bid. In other cases, the public power entity may view bidding as an opportunity to test the market. These entities might use the market offers as leverage to potentially get a better deal from the utilities with whom they have traditionally contracted for power.

Some bidders expressed the view that some public power RFPs were "just for show" or "too political" and that the public power utilities were not really committed to bidding or, moreover, to competition. Other noted their belief that RFPs issued by public power entities were less well defined in terms of needs, timing, or criteria and, in fact, were more exploratory and uncertain regarding the ultimate selection of projects or other outcomes than those emanating from investor-owned utilities. Finally, some frustration was voiced that since public power entities are generally not subject to state commission jurisdiction, bidders have no avenue to appeal the results or conduct of a public power solicitation.

There was some enthusiasm for having the Federal Energy Regulatory Commission (FERC) issue bidding guidelines affecting non-state regulated utilities.

Bidding Alternatives

As we noted in our 1990 bidding study, "even in states that have adopted it, bidding has not been the exclusive means of securing new capacity."[4] That remains true today. As noted earlier, in 12 active bid states, either commissions permit contracting outside bidding or such contracting was actually taking place. In addition, in a number of states where there is no bidding, utilities continue to negotiate and sign contracts with independent developers. Clearly, bidding is only one choice in the power purchase spectrum. Other methods of procuring capacity include: competitive negotiation (or other bidding-negotiating hybrid), other arms-length negotiation, and standard offer contracts.

Many bidders expressed a preference for competitive negotiation. Competitive negotiation is something of a hybrid, where bidding criteria are used as a "screen" through which qualified projects must pass before they can negotiate with the utility. Some bidders felt that a competitive negotiation system would be more likely to produce "real" projects than bidding because qualified potential suppliers could negotiate terms and conditions of the power sales agreement. It is important to note that most bidding systems permit or intend that some negotiation go on between the bid award and contract signing. In fact, most utilities procure fuel, turnkey plants, design and construction services, and other goods and services through a combination of bid and negotiation. An argument can be made that generating capacity should not be treated any differently.

Proponents of competitive negotiation claim that it represents an improvement over both bidding and negotiation for three reasons:

- Since the terms are not fixed, it permits developers to be more creative and tailor projects to the particular needs of the utility in terms of timing, siting, fuel supply, design, performance, security and contract termination provisions, among others, once they reach the negotiating stage;

- It removes the potential incentives for some bidders to offer unrealistic projects which will do well evaluated against set bidding criteria but may never get built; and,

- It offers a more rational way to screen qualified potential suppliers.

Competitive negotiation retains some of the objective elements and accountability of pure bidding without its perceived rigidity and inflexibility.

For example, under its new bidding rules, the Massachusetts Department of Public Utilities (MDPU) permits utilities, based on initial rankings, to negotiate with projects that fill 130 percent of the supply block.[5] In its commentary, the MDPU noted, "...the opportunity for negotiation appropriately provides the flexibility necessary to improve the final mix of projects. ...The negotiation process [represents] an opportunity for developers to improve projects."[6] In this case, the bidding system becomes more like competitive negotiation. The DPU recognized the need for flexibility in its bidding program. This encourages utilities to take advantage of the ability to negotiate with qualified suppliers. The evaluation criteria specified in the rules, although not mandating specific weights, require utilities to consider a wide range of non-price criteria.

Furthermore, at least one study suggests that negotiated contracts offer ratepayers additional value over contracts signed through "pure" bidding. A 1990 report by the Massachusetts Electric Company (MEC) comparing negotiation to bidding noted, "the report continues to demonstrate additional value found in negotiated contract non-price features versus bid contracts."

Many bidders expressed a preference for competitive negotiation.

The report found that the list of additional values in negotiated contracts versus contracts resulting from bidding included:[7]

- Utility right to approve design;
- Utility right to oversee construction;
- Utility right to specify maintenance schedule;
- Provisions for paying a supplier more than statutory minimum for power produced above ordinary contract amounts;
- Utility right to review and approve fuel supply contract, fuel transportation and renegotiation of fuel contract;
- Utility right to terminate if supplies are interrupted/halted;
- Loss of QF status as grounds for termination;
- Loss of QF status as grounds for rate regulation;
- Higher QF quality standards;
- Increased coordination between utility and QF; and,
- More effective balance of risks and rewards inherent in the operation of the QF.

Moreover, the MEC report stated that "flexibility was perceived by QF developers as the greatest strength of negotiation."[8] Citing the "Qualifying Facilities Survey" conducted by Temple, Barker, & Sloane in 1987, the MEC report indicated that 78% of those interviewed favored negotiation over bidding.[9]

Additionally, an independent analysis of non-price provisions concluded that, "From the standpoint of ratepayer benefits, most of the differences between the bid and negotiated groups made the negotiated contracts more valuable and less costly to ratepayers."[10] Finally, analysis of price projections of all projects in Massachusetts from 1987 to 1989 found that "prices between bid and negotiated contracts continue to be competitive."[11] That study appears to counter the conventional wisdom that bidding results in substantially lower prices than negotiated contracts.

However, it is important to note that aside from a few, highly publicized cases, virtually all bidding systems permit some negotiation between utilities and potential suppliers. To increase accountability in negotiation, commissions should subject negotiations to tight deadlines, such as those imposed by the MDPU rules. Many independents have experienced negotiations outside bidding which can go on for several years without resulting in a signed power sales agreement. Bidding is not immune from this problem -- in its 1989 bid, the Northern California Power Agency negotiated with bidders, but has yet to select any winners or sign any contracts.

Some bidders also preferred straight arms-length negotiation of contracts over any form of bidding, including competitive negotiation. Again, the bidders emphasized that negotiation permitted them to be more creative in structuring their proposed project to meet the utility's needs and restated their belief that negotiation would probably yield "real" projects. By contrast to bidding, straight negotiation is more of a first come, first served technique. The utility can choose to negotiate with some, all or none of the developers who approach the utility with proposed projects. With negotiation, there is no systematic way to ensure that all qualified projects are considered by the utility. In addition, there are no assurances that a utility will ever sign a contract, even if negotiations continue for a number of years.

Bidders liked standard offer contracts because they are relatively quick and easy to do. In general, standard contracts are generally no longer readily available in most places (Florida and California, to some extent, being the major exceptions). Some bidding states continue to have standard contracts available for small QFs or energy-only projects. Many of the bidders surveyed acknowledged that some of the experience with standard offers in the early days of PURPA implementation pointed up the pitfalls of relying on standard contracting. More so than negotiation, standard contracting offers no assurance that utilities will be offered as many qualified projects from which to choose.

Many independents have experienced negotiations outside bidding which can go on for several years without resulting in a signed power sales agreement.

While standard offer contracts proffer no panacea for the complexities of bidding or negotiation, standard terms in contracts signed through competitive bidding or negotiation can be helpful. In particular, project finance lenders, in lending large sums of money, prefer contract terms which have withstood the test of time and are less likely to be challenged. However, such standard contract terms must not impose conditions on power sellers which can make the project, impossible to finance.[12]

Finally, utilities and commissions we surveyed were generally satisfied with the results of bidding to date because of the number of projects offered. Of those responding, no one anticipated major structural variations in bid rules or programs. For example, some of the utilities noted that they anticipated making changes to bid evaluation criteria to more strongly emphasize environmental measures.

NOTES

1. Virginia State Corporation Commission, "Appendix A: Rules Governing the Use of Bidding Programs to Purchase Electricity From Other Power Suppliers," in *Ex Parte: In the matter of Adopting Commission Rules for Electric Capacity Bidding Programs*, Case Number PUE900029, Final Order, November 28, 1990. page 3.

2. Commonwealth of Massachusetts, Department of Public Utilities, 220 CMR 10.00, *Rules Governing the Procedure by Which Additional Resources are Planned, Solicited, and Procured by Investor-Owned Electric Companies*, page 17.

3. New York also permits contracting outside bidding under certain circumstances: 1) energy-only contracts, or 2) projects under 2 MW.

4. National Independent Energy Producers, *Bidding for Power: The Emergence of Competitive Bidding in Electric Generation*, Working Paper Number 2, March 1990, page 4.

5. Commonwealth of Massachusetts, Department of Public Utilities, 220 CMR 10.00, Section 10.04 (3)(e).

6. Commonwealth of Massachusetts, Department of Public Utilities, *DPU 89-239: Investigation by the Department of Public Utilities on its Own Motion into Proposed Rules to Implement Integrated Resources Management Practices for Electric Companies in the Commonwealth*, August 31, 1990, page 35.

7. Massachusetts Electric Co., *Alternate Energy Negotiation - Bidding Experiment, 1990 Report*, March 31, 1990, page 60 and 66.

8. *Ibid.*, page 61.

9. *Ibid.*

10. *Ibid.*, page 4.

11. *Ibid.*, page 58.

12. Examples of unfinanceable contract provisions which may impose severe economic risks on projects include: 1) absolute rights to terminate if a regulator disallows any portion of project costs or 2) certain types of foreclosure rights by utilities.

CHAPTER IV —
STATE REGULATORY COMMISSION TREATMENT OF ENVIRONMENTAL ISSUES IN BIDDING

The state of the environment is clearly one of the paramount concerns of the 1990s. The environmental trend will most assuredly influence the fuel, size, technology and other choices utilities make in selecting supply and demand-side resources to meet their load. There is a plethora of national, regional, state and local environmental standards, policies and interests which affect powerplant siting, construction and operation, and we will likely see new and more stringent ones as the decade progresses. For example, at the national level, Congress recently passed the Clean Air Act Amendments of 1990. Its acid rain provisions will affect nearly every existing and new fossil-fuel fired generating units. The 102nd Congress will likely consider amendments to the Clean Water Act and the Resource Conservation and Recovery Act (RCRA), both of which could ultimately affect a substantial number of powerplants.

It should come as no surprise then, that increasingly, environmental issues are finding their way into the design and structure of bidding programs. Clearly, regulatory commissions and utilities are responding to the heightened environmental concerns, and this trend is likely to have a long-lasting impact on capacity procurement. In this report, we look at two emerging issues related to environmental concerns:

- First, the treatment in bidding and contracts signed through bidding or other competitive procurement, of unanticipated changes in regulatory compliance costs, particularly those resulting from new environmental standards; and,

- Second, the treatment of environmental externalities or residual environmental costs in bidding systems.

We polled bidders, state commissions and utilities regarding both of these topics.

The Treatment of Changes in Regulatory Compliance Costs

Environmental regulation is constantly evolving and getting stricter. In planning to construct a long-lived asset such as a powerplant, it is prudent to assume that at some point in its life, the plant will become subject to increasingly rigorous environmental standards. Harder for project developers to predict or foresee is the shape and scope of new standards. Some of the questions which arise in this context include:

- Will new laws and regulations affect air, land, water, noise or any combination thereof related to siting of, or emissions from, powerplants?

- Will new standards require the plant operator to more rigorously prevent pollution, limit emissions or deal with the disposal of ash or other waste products?

- Will they require developers to make large capital expenditures to install new control technologies or increase operations and maintenance expenses? or,

- Will they have entirely different unforeseen effects?

The treatment of unforeseeable regulatory compliance costs in contracts signed through a competitive process can have severe impacts on project economics. These retroactive costs affect existing fixed price or fixed term contracts. For example, in its new bidding rules, the Virginia State Corporation Commission noted the peril regulatory changes could hold for fixed priced contracts, stating it would not require utilities to be held to its cost estimates for new plants in part because of the potential financial liabilities created by costs of future environmental compliance. Under traditional cost-of-service ratemaking, utilities are entitled to recover all prudently incurred costs from their ratepayers. Utilities, unlike contract power suppliers, are able to pass all these costs, including costs to comply with new regulatory standards, directly through to their ratepayers and recover the costs subject, of course, to prudence review. This differential treatment of fixed price contracts and cost-of-service ratemaking can confer a competitive advantage for utility cost-of-service plants in the evaluation of resource alternatives.

As environmental concerns continue to grow, the cost impact of regulatory changes on fixed-term power purchase contracts will become increasingly important to project economics. This problem is not unique to power purchase agreements — it is potentially common to other long-lived, fixed price or term contracts. For example, in areas such as fuel contracting, utilities and coal suppliers have, over many years, worked out the contractual treatment of black-lung payments, and other regulatory costs. However, as noted earlier, power purchase contracts generally do not contain mechanisms to pass through increased costs due to unanticipated regulatory changes, while utilities can pass those costs to the ratepayer, subject to a prudence standard.

Theoretically, economic efficiency requires that risk be assigned to the party best able to manage those risks. In power sales agreements, many developers will take on some risks, such as environmental permitting risk, interest rate risk and financial risk for non-performance. Developers will then try to share other risks, such as project delay, construction cost or completion risk, with engineering and construction contractors or equipment suppliers who are better able to control those costs and schedules. Under some power sales agreements, utilities and their shareholders continue to bear force majeure risk and prudence risk. Some risks, such as fuel costs, remain with the ratepayer, and are managed by indexing costs in contracts. For example, in the power sales agreement signed with non-utility suppliers, Virginia Power indexes fuel costs to market related measures.

Who best can manage regulatory compliance cost risks is not as clear. Developers generally have little control over them and are not able to foresee them. In addition, unlike fuel price provisions, these costs do not lend themselves easily to indexing to control risk. The impact of compliance costs on the continued economic viability of project can be enormous. For example, changes in Best Available Control Technology requirements between contract signing and operation can necessitate large capital expenditures. The stability of the independent power industry would be increased if commissions were to adopt principles to govern how these risks should be managed and distributed withing the bidding framework.

Bidders surveyed were fairly evenly split as to whether they attempted, in some way, to account for unanticipated regulatory changes in bids which they submitted or contracts which were subsequently signed. Some bidders noted that they had increased their asking price to try to reflect the risk of unanticipated regulatory compliance costs. For example, some bidders attempted to build a cushion in the project rate of return to account for these risks. The vast majority of bidders responding noted that their contracts do not have any type of pass-through provisions for environmental or other regulatory compliance costs, although a number of bidders had tried unsuccessfully to include some kind of pass-through mechanism in their proposals.

When asked how this question could be addressed, most developers expressed a preference for the state public service commission to permit the pass-through of major increases in regulatory compliance costs. The second most popular choice among developers would be to permit utilities and independents to negotiate contract changes with utilities to account for these increased costs. The utilities who responded were split between those who do not permit pass-through, because they view environmental compliance costs as an suitable risk for project developers to bear, and those who expressed that they feel it appropriate for commissions to permit developers and utilities to negotiate the treatment of those costs.

The state commissions also did not share bidders' enthusiasm for permitting pass-through of these costs. The New Jersey Board of Public Utilities (NJBPU) does not allow the pass-through of unanticipated regulatory compliance costs. The NJBPU orders contain language which state that contracts, once approved, should not be modified by future Boards. (It is not clear whether a contract clause permitting pass-through could be included in a contract approved by the NJBPU.) It noted that other regulatory changes, such as environmental compliance, were appropriate contract risks for developers. The California Public Utilities Commission (CPUC) noted it had not addressed the issue directly yet, but would likely permit a developer to approach the utility and commission to renegotiate contract terms if the developer could demonstrate hardship resulting from cost increases.

The Virginia State Corporation Commission (VSCC) permits the developer and utility to negotiate treatment of these costs, but rejected the idea of straight pass-through. The VSCC's new bidding rules state:

> "the developers have elected to operate in an unregulated environment and accordingly, the developer, not the ratepayer, must shoulder the majority of risks associated with the project. To some extent, the changes in environmental requirements are a risk which must be factored into the decision to build a power plant. To the extent an extreme circumstance arises, the parties are always free to re-evaluate the existing contract. If the project is still viable, the parties may negotiate appropriate amendments to the contract."[1]

Of other states which evaluate power purchase contracts, a number noted that they felt unable to bind future commissions, while seven states noted that either by commission policy or by practice, contract approvals were considered to be binding. A far more serious concern which most commissions have yet to address is whether commissions view the contract terms and prices as immutable and therefore will not permit renegotiation or pass-through.

Ideally, many developers would like to be able, as utilities are, to pass these changes in costs through to ratepayers although we suspect many would be unwilling to accept increased regulatory scrutiny of project costs in return. However, a number of different views on the treatment of changes in regulatory compliance costs in various industry sectors have surfaced. For example, in a recent article, a state regulator suggested the two following principles: "First, the contract provisions should be clear enough so that cost responsibility can be assigned....The second principle is that of symmetry."[2] This suggests that developers to qualify for relief from increased costs, would have to be willing to flow cost decreases resulting from a change in regulation back to ratepayers.

By contrast, developers suggested these three principles: "First, these new environmental requirements ... are not reasonably foreseeable at the time bids are submitted. Second, non-utility power producers will be placed at a competitive disadvantage with comparable cost-of-service plants proposed by utilities. ... Finally, because the more stringent environmental requirements are adopted at the demand and for the benefit of the general public, it is appropriate that the resulting costs should be shared by ratepayers and not imposed on developers alone."[3]

Treatment of Environmental Externalities

Environmental externalities are the residual environmental impacts of a powerplant which remain after compliance with existing environmental standards. For example, the health cost associated with uncontrolled stack emissions of various pollutants would be considered an externality cost. Long touted by economists as the only way to measure true social costs and therefore make efficient decisions regarding resource allocation, measuring environmental externalities from powerplants have only recently been included in least-cost or integrated resource planning. Many claim that renewables and conservation, as well as highly-energy efficient technologies, which may be more expensive in actual or monetary costs relative to some fossil fuel technologies, will prove to be less expensive on a social cost basis when the externalities associated with fossil fuel are internalized. Therefore, it is argued, if externality costs are included in the resource procurement process, utilities and regulators will make more economically efficient choices among supply and demand alternatives.

Consideration of externalities in the utility planning process is a growing phenomenon as states attempt to get a handle on least-cost planning. As of July 1990, 17 states had adopted rules or policies on the treatment of externalities, although most of these states had not yet actually tested their policies in a resource planning or procurement process. In addition, seven other states are evaluating and developing methodologies for including externalities in resource planning or bidding.

Ideally, many developers would like to be able, as utilities are, to pass these changes in costs through to ratepayers although we suspect many would be unwilling to accept increased regulatory scrutiny of project costs in return.

Attempting to incorporate the social costs associated with the externalities of power production can distort costs and lead to economically inefficient options if not done carefully. Externalities can influence the choice among alternatives, literally discriminating against certain fuels, giving utilities and developers strong incentives to behave in certain ways and affecting the actual cost of electricity for ratepayers. For example, with social cost pricing, a utility may forego a coal-fired power plant in favor of a renewable project which, although more expensive in terms of actual costs, is cheaper on a social cost basis. However, ratepayers pay a "premium" for that block of electricity. Furthermore, imperfect or badly designed externalities policies, by not reflecting true social cost can favor certain resource choices, and may make power markets less, rather than more, efficient.

This report will focus on the methods being contemplated for considering environmental externalities and the impact the methods are likely to have on the results of bidding. Some states, such as Arizona, Minnesota and Nevada rely on qualitative methods which give preferences to less-polluting technologies. Other states, such as Wisconsin and Vermont, permit cleaner resources to cost more than other technologies or discount their prices. Finally, some states, such as New York or Massachusetts, quantify externality costs based on actual emissions.[4] Bidders who responded preferred methodologies which assign specific costs to the environmental impact of each pollutant, because presumably, those programs are the most straightforward. Some bidders also expressed some inclination towards weighing specific technologies according to their relative environmental benefits or harm. (As with assigning specific costs, this involves quantifying relative environmental effects.)

Nearly all bidders responding to the survey indicated that externalities should be taken into consideration in bidding. For ratepayers to fully benefit from more efficient markets, power markets should, after careful and balanced analysis, reflect some measure of true or total social cost. As a 1990 article which discussed New York State's rules on externalities in bidding noted:

> "Failure to consider these residual impacts in competitive bidding programs may penalize environmentally superior resources and allow bidders of low cost, polluting resources to win contracts and reap excessive profits which would not be passed on to those affected by the pollutants. Including externalities in bidding programs is a way to create a level playing field for environmentally clean resources and provide bidders with some incentive to minimize the total costs of their projects, including the indirect costs to society."[5]

Conversely, if externalities are applied inappropriately in highly sensitive and response markets, they could lead to countless distortions and inefficiencies. In applying an externalities policy to bidding, a number of issues of importance to non-utility generators may arise:

1. Will non-utility supply and demand resources be treated equally when compared to utility resources?

   Clearly, the consideration of externalities should be neutral with respect to whether a utility or independent owns a supply or demand resource. In this vein, we note two concerns. First, externality policies generally only evaluate the environmental costs of new plants, and do not consider the social cost of utilities continuing to run older, less efficient, more polluting plants. Second, in many states, development of externality rules is undertaken in the context of, or for the purpose of, encouraging demand-side programs. States, by offering incentives to encourage utilities to undertake their own demand-side or conservation programs, may inadvertently discriminate against potentially cost-effective and environmentally benign independent supply and demand-side providers. The incorporation of externalities into resource planning processes will most certainly help demand-side resources, but ratepayers may suffer if any supply or demand-side programs are removed from the competitive arena.

2. How are externalities incorporated into the bidding program -- specifically, what costs are considered and how are they measured?

   Ideally, all unquantified social costs should be considered externalities. However, this is impractical, certainly in the context of bidding. But considering only some environmental impacts and not others may yield strange and unintended results. For example, New Jersey, in attempting to quantify externalities to promote demand-side management, has proposed that nuclear power not be assigned any externality costs (e.g. the policy would not take into account the environmental effects of spent nuclear fuel or the potential health risk from nuclear accidents). States must make some determination how far into the "fuel cycle" they begin to measure effects on the environment.

The New York State Public Service Commission (NYSPSC) and the Massachusetts Department of Public Utilities (MDPU) externality rules begin to measure social costs at plant operation. The Massachusetts rules state, "A priority should be placed on estimating environmental externalities that are the direct result of power-plant operation, including all downstream effects. The Department directs electric companies to consider in the project evaluation process all impacts resulting from plant operation including air, water, solid waste, and spent fuel disposal impacts, and resource use."[6] New York assigns points to bids based on the relative impacts of proposed projects from air emissions of SO_2, NO_x, CO_2 and particulates, the effect on water quality, land use, aesthetics, noise and water disposal.[7]

In addition, there are countless ways in which externalities can be measured, such as measuring the relative toxicity of various pollutants, valuing the direct damage effects of pollutants, or determining what society is willing to pay to reduce the pollutant. Much of the recent literature favors marginal control cost as a proxy for damage costs.[8] For example, one recent article noted, "The cost of required control measures serves as an estimate of the price society is willing to pay to reduce the pollutant ... The cost of required controls may directly establish the social benefits of reducing emissions."[9] Both the NYSPSC and the MDPU require that externalities be quantified and assigned weights or scores based on the estimated environmental impact of a specific project and measured by the marginal control cost for those impacts. Bidders' stated preference was for assigning costs to specific pollutants, which is the approach adopted by the Massachusetts DPU. While we do not necessarily endorse the specific findings or valuations, the NYSPSC and MDPU models seem preferable to strictly qualitative measures of externalities.

The consistent feeling among developers was that some relatively objective measure of externalities was preferable to any subjective conclusion, such as stated preferences for certain technologies. A number of respondents cautioned that while consideration of externalities should be applied consistently, policies should be flexible enough to detect the subtle differences in environmental impacts among projects. Almost none of the bidders surveyed expressed the opinion that externalities need not or should not be specified at all.

There has recently been a great deal of discussion and examination of ways to incorporate environmental externalities into both least-cost planning and bidding. However, to help assure that these programs meet their stated objectives, it is important that the process of establishing externality costs solicit input from all potential suppliers. Some of the innovative approaches to including externalities in the evaluation of bids suggested by respondents included:

- Taking into account the "location specific nature of pollutants." For example, should the environmental impact of a facility located in a heavily populated area be viewed differently than one in a rural area?

- Adopting programs which permit or encourage bidders to offset their externalities. For example, a bidder offering a coal plant might propose to plant trees or buy land for conservation to offset CO_2 emissions.

- Examining policies which use market-tested or market-based indicators of social cost.

- Running the electricity system according to "environmental dispatch" which might value a new plant on the basis of displacing a more polluting existing technology (This could solve the inefficiencies potentially created applying social costs only to incremental or new generation).

The consistent feeling among developers was that some relatively objective measure of externalities was preferable to any subjective conclusion, such as stated preferences for certain technologies.

How Will SO_2 Emission Allowance Credits be Treated in Bidding?

In the Clean Air Act Amendments of 1990 (CAAA), Congress attempted to internalize the externalities associated with sulfur dioxide (SO_2) emissions from power plants by creating a system of marketable SO_2 emission allowances. Although we did not address this topic in our survey, its implications for bidding may be extremely important. To cap total emissions, in addition to mandating existing units to limit their emissions, Congress required new units to hold allowances equal to their total SO_2 output. Existing units are allocated allowances equal to the plant's total SO_2 emissions at specified rate (1.2 lbs SO_2/mmBtu by 2000). New units are issued no allowances.

This creates an obvious strain on bidding systems. Utilities will be loath to sign long-term power sales agreement unless the new units can demonstrate that they have allowances available to them. In addition, the price of SO_2 allowances in the market may affect the outcome of competition. NIEP believes that for competitive power markets to flourish, allowance markets must flourish too.

Section 403(f) of the CAAA states that the acid rain provisions should not "... be construed to interfere with or impair any program for competitive bidding for power supply."[10] State regulators should do everything in their power to assure that allowances in their state be available to the most cost-effective units and to ensure that bidders who need allowances are afforded a reasonable, fair and timely opportunity to obtain allowances.

NOTES

1. Commonwealth of Virginia, State Corporation Commission, *Ex Parte: In the Matter of Adopting Commission Rules for Electric Capacity Bidding Programs*, Case Number PUE900029, Final Order, November 28, 1990, page 6.

2. Steve Aos, Director of Policy and Planning, Washington Utilities and Transportation Commission, "The State Regulatory Commission View," *Robertson's Current Competition*, Volume 1, Number 3, November 1990, page 5.

3. John Sachs and Harrison Wellford, "The Non-Utility Generator Perspective," *Robertson's Current Competition*, Volume 1, Number 3, November 1990, page 10.

4. Cohen, Eto, Goldman, Beldock and Crandall, "Environmental Externalities: What State Regulators Are Doing," *The Electricity Journal*, Volume 3, Number 6, July 1990, pages 25-29.

5. S. Putta, "Weighing Externalities in New York State," *The Electricity Journal*, Volume 3, Number 6, July 1990, page 42.

6. Commonwealth of Massachusetts, Department of Public Utilities, *DPU 89-239*, August 31, 1990, page 79.

7. "Weighing Externalities in New York," page 47.

8. Marginal control cost serves as a proxy for damage costs since, in theory, society would be willing to pay to control pollution no more than the implicit value of the environmental damage.

9. P. Chernick and E. Caverhill, "Methods of Valuing Environmental Externalities," *The Electricity Journal*, Volume 4, Number 2, March 1991, page 50.

10. U.S. House of Representatives, "Clean Air Act Amendments of 1990: Conference Report to Accompany S. 1630," Report 101-952, October 26, 1990, page 202.

CHAPTER V — IMPACT OF BIDDING ON UTILITIES

In the context of this study, we could not hope to examine the entire range of impacts of bidding on utilities. This chapter focuses on two issues of increasing importance for utilities who host bids:

- The treatment of repowered plants in bidding; and,
- Financial issues for utilities raised by bidding.

The Treatment of Repowered Plants in Bidding

The repowering of existing plants is an increasingly popular strategy for utilities to meet new demand. Over the past forty years, ratepayers and utility shareholders have invested many billions of dollars in powerplants. Fossil-fuel fired powerplants are designed to run and will typically be fully depreciated (with full recovery by the utility of capital costs) over thirty to forty years. Many of the baseload plants constructed in the 1950s and 1960s are now nearing the end of their useful lives. According to the Department of Energy, the number of fossil-fuel generating plants 30 years or older will increase from about 2,500 in 1989 to approximately 3,700 in 1998, increasing the share of generating capacity represented by these plants from 13 percent in 1989 to 27 percent in 1998.[1]

In the past, utilities generally replaced aging plants with new units, since new units were often much more efficient and less expensive to construct and operate. However, the experience of the last fifteen years has drastically changed utilities' outlook towards their existing generating base. Large new generating stations no longer exhibit declining unit costs and, in fact, have become very costly. In addition, a recent report from the General Accounting Office noted, "In recent years, however, increased financial risks, uncertainties about future demand and other factors associated with constructing new plants have led utilities away from readily building new plants."[2]

Furthermore, with the increasing difficulty of siting and permitting new powerplants, repowering or life-extension has become a very attractive option for utilities. According to the Department of Energy, life-extension can be as little as one-tenth the cost of constructing a similar new unit.[3] Even in comparison to a new gas-fired generating unit, which is several hundred dollars per kilowatt (kW) cheaper than a new coal plant, repowering or life-extension of a coal plant may appear to be a more cost-effective option for utilities.[4] Finally, with the expected legislative or regulatory resolution of the "WEPCo decision,"[5] utilities should be able to determine with relative certainty the extent to which repowered or life-extended plants must comply with "new source performance standards" or undergo "new source review" required by the Clean Air Act.

In the context of bidding, repowered plants give utilities several options. First, a utility may choose to use a repowered plant as the benchmark or "avoided" unit against which all bids are measured. Second, a utility could remove a fully depreciated plant (one for which ratepayers have ceased paying) from its ratebase and bid it in its own service territory or into another utility's solicitation. Under either scenario, on straight cost comparison, the repowered plant will likely be cheaper than a "greenfield" or new plant. Repowered plants, in addition to needing limited capital expenditures, are already sited and have interconnections in place.

How will the ratepayer best benefit from solicitations in which both repowered plants and new units are proposed? How can commissions ensure that ratepayers get the best deal if a utility bids a repowered plant or uses a repowered plant as its benchmark? First, regulators should decide what is a "fair" determination of the price assigned to a repowered plant. This includes not only a measure such as life-cycle cost or "fair market value" but consideration also of the reliability of older plants and their relative environmental impacts compared with new units.

The repowering of existing plants is an increasingly popular strategy for utilities to meet new demand.

When surveyed, bidders generally did not like the idea of bidding against a repowered plant, since many felt the outcome would be pre-determined. One developer said, "We have useful things to do with our time." Others suggested they would only bid against a repowered plant if the supply block was bigger than the repowered plant or if the utility were held to its bid price or cost estimate for that plant. Bidders voiced strong concerns about a utility using a repowered plant as its avoided plant for the same reasons. In addition, they expressed a concern over how the cost of the avoided plant would be measured.

Some bidders suggested that regulators could find reasonably fair ways to compare the true costs of a repowered plant to a new plant. For example, commissions could compare life-cycle capital and operating costs of an existing plant to a new plant, and assign cost penalties to the existing plant where appropriate for lower efficiencies or reliability. Bidders' suggestions for pricing repowered plants, included: "fair market" value, cost plus, cost to repower or cost to repower plus the expense to bring the plant up to environmental standards for new plants. The state commissions we surveyed generally favored permitting utilities to bid repowered plants, but some expressed concern about the difficulty of a fair comparison of alternatives given potentially unequal lives, contract terms, differences in efficiency, availability, emissions and operation and maintenance costs. In addition, we conducted a follow-up survey of all state commissions, and found that most have not not begun to address the treatment of repowered plants in bidding.

One state, New York, has recently confronted this issue when a jurisdictional utility, Niagara-Mohawk (Ni-Mo), selected its own repowered plant in a recent solicitation. Ni-Mo provided the Commission with a narrative explanation of the basis for its selection. The PSC will not officially review the price assigned to the plant and the bid results until the utility seeks to recover its costs in rates. The Commission staff indicated they may review the environmental impacts of Ni-Mo's selection of a repowered plant in an overall review of environmental issues associated with bidding.[6]

Financial Issues for Utilities Hosting Bids

Since utilities began purchasing power from Qualifying Facilities ten years ago, commissions have treated the costs of QF power as an expense item. As with fuel or operations and maintenance costs, the utility is entitled to recover purchased power costs from ratepayers, but does not earn a return. This was done, in part, to hold utility debtholders and shareholders harmless for those purchases, even though the purchase price usually has a capital (capacity) component and a variable (energy) component. In rate-making, commissions have treated power purchased through bidding the same way as QF purchases.

However, recently, two major credit rating agencies questioned whether power purchases should, in fact, be considered the equivalent of debt and therefore potentially affect the financial health of the buying utility. In reports issued in 1990, both Standard & Poor's and Moody's Investor Service stated that they would more carefully examine the financial implications of a utility's reliance on purchased power and would adjust credit rating if necessary. Specifically, the agencies "suggest that under certain conditions the purchased power contracts would be treated as a fixed obligation (debt equivalent) and that they would recalculate a utility's outstanding debt and cash flow coverage ratios as a result."[7] Coverage ratios measure what portion of a utility's cash flow is committed to debt or other fixed payments. Lowering a utility's credit rating as a result of losing financial flexibility in this way could make its capital more expensive.

Although neither rating agency has yet downrated a utility based on criteria discussed in their reports, at least one utility has suggested to its commission that its avoided cost be lowered to account for the potential impact on its credit rating.[8] Another utility, Delmarva Power & Light, attempted to include what they labeled an "equity adjustment factor" (EAF) in their bid evaluation criteria to account for possible credit deterioration. A Maryland Public Service Commission hearing examiner recently rejected the EAF as speculative. The rating agencies' reactions to power purchases will no doubt be watched closely by utilities, commissions and non-utility developers.

Bidders' responses were somewhat split as to whether utilities should be permitted to include the potential effect of power purchases on credit ratings, and ultimately the cost of capital, in RFPs. Many bidders felt that it would be difficult, if not impossible, to quantify, verify, or apply any generic solution to the potential financial impact of power acquired through bidding. In their comments, the ratings agencies stated explicitly that the specific circumstances and provisions of the contract, the utility's purchasing practices, and regulatory treatment of the contract would affect their evaluation. Moreover, some bidders noted that equal consideration should be given to power purchases which strengthen a utility's financial picture by, for example, diversifying fuel mix. The commissions surveyed were naturally concerned about any real cost impact on ratepayers stemming from the potential effect on a utility's credit rating.

In this context, it is important to remember that utilities have contractual tools to mitigate the risks associated with purchasing power. In contracts, utilities can:

- Require front end deposits to guarantee the project is constructed on time.
- Specify minimum standards for equipment, warranties and guarantees provided by equipment suppliers.
- Require an operating escrow account which can be drawn on if the system is damaged or the equipment does not perform.
- Specify annual testing of equipment to determine that it meets the contract standards, with penalties if it does not.
- Require security interests in fuel supply contracts.

A related financial matter concerns incentives for utilities to purchase demand or supply-side resources. Both demand and supply purchases are treated as expense items from which utilities cannot profit even if they represent a good deal. Therefore, some argue that utilities have no incentive, and in fact disincentives, to acquire resources, rather than add their own generation to ratebase. Demand-side resources face an additional hurdle, since they can erode a utility's revenues if there is not prompt recovery of program costs. Many argue that incentives would make utilities financially "indifferent" whether they acquire resources from third parties or make additions to ratebase, as long as they secure the best deal for their ratepayers.

A study by the National Association of Regulatory Utility Commissioners (NARUC) summarized the dilemma for utilities as follows, "Each kWh a utility sells, no matter how much it costs to produce or how little it sells for, adds to earnings; ... Purchases of power from cogeneration, renewable resources or other non-utility sources add nothing to utility profits, no matter how cost-effective these resources are."[9] The argument for demand and supply side incentives is the same — under current rate regulation, utilities do not profit from either power purchases or conservation programs.

Around the nation, 28 commissions have initiated or are examining financial incentives for utilities to pursue demand-side management programs.[10] By contrast, only one commission (Kansas) has adopted similar incentives for power purchases, while seven others (Maine, Massachusetts, Michigan, New Jersey, Oregon, Texas and Washington) are reviewing them.[11] More than half of the bidders surveyed favored some kind of supply-side incentives to remove the perceived financial disincentives for utilities who purchase power rather than building a plant themselves. However, a number of bidders stated that minimizing the cost to ratepayers through power purchases should be ample incentive for utilities. Some developers expressed that offering incentives may run counter to the goal of promoting beneficial competition in power markets.

Proposing supply-side incentives raises three issues for policy-makers to consider:

- As with demand-side inducements, do compelling economic or financial justifications exist for supply side incentives?
- What is the potential financial impact on ratepayers of offering such incentives?
- How might supply-side incentives affect competition overall?

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Some developers expressed that offering incentives may run counter to the goal of promoting beneficial competition in power markets.

NOTES

1. US General Accounting Office, *Electricity Supply: Older Plants' Impact on Reliability and Air Quality*, GAO/RCED-90-200, September 1990, page 17.

2. *Ibid.*, page 8.

3. The GAO report noted, "According to estimates by DOE, the cost of extending the service life of a coal-fired plant ranges from $89 - 230 per kW of generating capacity compared to a range of $1294 - $1378 per kW of generating capacity for building a new coal-fired plant." page 14.

4. At approximately $800 per kW, new gas fired units are still more expensive than repowering or other life-extension of a coal plant.

5. On May 23, 1991, the Senate Energy and Natural Resources Committee reported out, S. 341, its comprehensive energy bill, which included provisions relating to applicability of new source review to existing power plants. On June 6, 1991, EPA issued a notice of proposed rulemaking on the same subject. Neither has been acted upon yet.

6. Telephone Interviews with J. Brew and M. Reeder, NYS PSC Staff.

7. Naill and Sharp, "Risky Business: The Case for Independents," *The Electricity Journal*, April 1991, page 55.

8. *Ibid.*

9. NARUC Study findings summarized in Schultz and Eto, "Carrots and Sticks: Shared Savings Incentive Programs for Energy Efficiency," *The Electricity Journal*, Volume 3, Number 10, December 1990, page 32.

10. The following commissions have adopted demand side management incentives for utilities:

    California, Colorado, Connecticut, Georgia, Iowa, Maine Massachusetts, New Hampshire, New Jersey, New York, Ohio, Oregon, Rhode Island, Vermont, Wisconsin, and Washington.

    The following commissions are reviewing demand-side management incentives for utilities:

    Arizona, District of Columbia, Illinois, Kentucky, Maryland, Michigan, Nevada, North Carolina, North Dakota, Oklahoma, Texas, and Virginia.

    Source: *Robertson's Current Competition*, Volume 2, Number 5, May 1991, page 15.

11. *Robertson's Current Competition*, page 15.

CHAPTER VI —
GUIDELINES FOR COMPETITIVE PROCUREMENT

Bidding is the most visible instrument of competition, but it is by no means the only one. It is important not to view bidding as an end in itself, but to judge it by how it succeeds in delivering the most efficient power to the market and to the ratepayer. The issues discussed in this report reveal tangible concerns expressed by bidders, utilities and commissions about the competitive process. By addressing these concerns of bidders, we hope that the recommendations can improve the quality of competition and lead to better results for ratepayers.

Bidding represents one strategy for obtaining new capacity in a much wider continuum. Utilities and commissions are constantly attempting to find which competitive procurement model best serves their particular needs. For example, Texas Utilities (TU) recently announced that it was seeking alternative proposals to 2,162 MW the utility proposed to build for itself.[1] The "information request" stated the timing and size of the capacity additions TU was planning to make. By contrast, others seeking to meet incremental capacity needs, such as the seven investor-owned utilities in New York, must issue RFPs subject to comprehensive commission rules.

At its best as a method of acquiring capacity, bidding structures or frames the competition and seeks to prevent mischief by utilities or potential suppliers. On the other hand, bidding can be too rigid and overemphasize some kinds of criteria inappropriately over others. Also, where bidding is present, negotiated contracts may be discouraged.

Moreover, competitive power markets may be in flux where the utility's role is unclear. A fundamental question in these markets is how should utilities compete or their proposals be evaluated now that it appears many utilities are apparently interested in constructing new plants? For example, Baltimore Gas & Electric has filed an application with the Maryland Public Service Commission for certification to construct up to 800 MW of new capacity even though it has told the commission it is negotiating with as many as 20 independent developers. On the demand-side, a number of utilities and states are developing conservation programs and incentives for utilities while at the same time issuing or considering RFPs for non-utility DSM services.

Non-bid procurement systems challenge bidding. But they all share the same goal: to provide an unbiased method for selecting from among all potential sources those resources which best meet the needs of the utility's ratepayers. In soliciting those resources, the system should both encourage many potential suppliers to offer the best product possible, permit a neutral assessment of those offers against the utility' own proposal and yield projects which serve ratepayers reliably at reasonable costs. States and utilities need to assess which type of competitive process is most appropriate.

As we noted in our 1990 report, no matter how utilities or states structure the competition, as a first step, states should determine their energy needs and resource acquisition priorities. Once the need is identified, states can make rational decisions about capacity procurement and define, in some systematic way, the role of bidding, negotiation, demand-side management, utility construction or other alternatives.

The following recommendations represent a synthesis of the concerns of bidders, utilities, and state regulators expressed in the NIEP survey.

A. Integrated Review of Resource Options

While formal bidding, negotiated contracts outside bidding, and competitive negotiation all have a place in a competitive procurement system, their common denominator should be integrated resource planning to determine long-term resource needs, coupled with a contract review process which ensures that all selected resources — whether third party supply, conservation and DSM, utility construction, or repowered facilities — conform to the plan and to the rules of fair competition. Developers should view these processes as insurance for the integrity of the power market in a given state. Such a system would hold utilities accountable to state commissions, developers and the public for their resource acquisition decisions in the context of available alternatives.

It is important not to view bidding as an end in itself, but to judge it by how it succeeds in delivering the most efficient power to the market and to the ratepayer.

To promote a competitive environment for resource acquisition, an integrated resource planning and contract approval process should:

1) Allow public participation in the development of competitive bidding or negotiation programs conducted pursuant to an integrated resource plan;

2) Require utilities in all cases to submit fixed price bids. Utilities should be bound by their bid price if costs exceed projections, but also be permitted to retain any difference between the bid price and eventual cost in the event of lower than anticipated costs;

3) Make public the methodology for determining scoring, ranking, and pricing;

4) Provide for commission pre-approval of contracts for new generating facilities and require that utility-built facilities be subjected to the same regulatory review imposed on third-party facilities; and,

5) Permit negotiation and contracting outside bidding when consistent with the integrated resource plans' objectives of promoting renewable technologies, innovative project design, DSM or other resource options which are not easily accommodated in the formal bidding process.

B. Competitive Negotiation

Bidders' skepticism over the value of bidding as it is currently practiced is troubling. With the costs and time that goes into preparing a bid, if bidders feel that bidding is unfair or rewards what they consider to be the "wrong" kinds of projects, they will no longer bid. Ratepayers will ultimately suffer if potential, qualified suppliers stay away from the competition. Policymakers should consider the following:

- First, by carefully assessing the bidding data available, we can attempt to correct any misconceptions about bidding. Despite the stated dislike towards bidding, bidders are continuing to respond to RFPs in great numbers. As of May 1991, eight megawatts were bid for every one awarded,[2] a number comparable to the statistics from the end of 1989.[3] But this ratio is not necessarily the best measure of whether bidding is successful.

  In addition, to date, neither the small (relative to expectations) percentage of winning projects canceled (13.5 percent) nor the number of delayed or "troubled" projects offer compelling evidence that bidding will result in unreliable projects or favor plants which will ultimately fail. Therefore, it is critical to continue to monitor these kinds of bidding statistics to discern whether bidding's perceived inadequacies are indeed turning into fatal flaws.

- Second, utilities and regulators should examine whether hybrid systems such as competitive negotiation can lead to "better" contracts and projects. In competitive negotiation, bidding criteria becomes a screen for qualified projects. The Virginia and Massachusetts bidding rules permit utilities to make preliminary awards in excess of needs, which leads utilities into a negotiation with developers in the "initial award group."

As a better approach than "pure bidding," or "pure negotiation," some bidders advocate "competitive negotiation." By "pure" or "mechanical bidding", we mean a system in which potential suppliers offer a product which is then evaluated against fixed criteria to determine the group who will receive power sales contracts. Some criticize pure bidding for focusing too heavily on price and for being so mechanical that it cannot accommodate the subtleties necessary for effective project development. At the other extreme, "pure negotiation" while permitting more flexibility and room for creativity, offers little systematic accountability or verifiability of its results as bidding or competitive negotiation.

According to bidders, hybrid systems, such as competitive negotiation, retain some of the objective elements of pure bidding without its perceived rigidity and over emphasis on price. In competitive negotiation, bidding criteria become a screen to qualify projects for negotiation. The negotiation is competitive because the number of megawatts offered by the pre-qualified projects may greatly exceed the number requested. Some bidders assert that negotiated contracts can be more responsive to specific project considerations and thus, will produce contracts and projects more likely to succeed in the long run.

In some instances, competitive negotiation can produce a better over-all bidding procedure. A 1990 report of the Massachusetts Electric Company found an "additional value in negotiated contract non-price features versus bid contracts." The same study found no significant price differences between resources acquired through negotiation and bidding.

NIEP recommends competitive negotiation as an alternative to price-driven bidding for the following reasons:

1) since the terms are not fixed, it permits developers to be more creative and tailor projects to the particular needs of the utility in terms of timing, siting, fuel supply, design, performance, security and contract termination provisions, among others, once they reach the negotiating stage;

2) it removes the perceived incentives for bidders to offer unrealistic projects which may do well evaluated against set bidding criteria but may never get built; and,

3) it offers a more rational way to screen qualified potential suppliers. Utilities generally acquire many goods and services, including fuel supply, engineering, design and construction services through competitive negotiations.

C. Contracting Outside Bidding

Where there are rules and procedures governing bidding, should contracts be awarded outside bidding? To address this issue, policymakers should strike a balance between accommodating projects which offer unique benefits to ratepayers but are otherwise incompatible with bidding and, a fair system where everyone can compete to supply power on equal terms and conditions. The need to ensure that all competing projects are evaluated on a comparable basis suggests the need for adaptability in permitting capacity to be procured outside the bidding framework.

Clearly, a competitive bidding system needs to be flexible enough to permit resource acquisition outside bidding where it will be beneficial to ratepayers. FERC, in its 1988 Notice of Proposed Rulemaking on bidding, conceived of bidding as a useful but non-exclusive method of procuring capacity.

Projects which do not lend themselves well to all-source bidding generally have any or all of these characteristics:

- relatively long-lead times associated with siting, permitting, licensing and construction or completion schedules beyond the developer's control;

- projects which need to be concluded quickly;

- relatively high up-front capital costs and low operating costs (including projects which provide power to more than one utility); and,

- unquantified environmental or other benefits relative to other technologies being bid.

These attributes in many cases describe renewable energy projects. Many states are contemplating inclusion of environmental externalities to try to render fossil-fuel, renewable and other non-fossil options comparable, at least from the perspective of relative environmental impacts.

Guidelines for Awarding Contracts Outside of Bidding

NIEP recognizes the trade-off between giving utilities the flexibility to respond to special opportunities outside bidding and the need to protect the integrity of the bidding process. Most bidders would favor giving utilities the flexibility to contract outside bidding in special circumstances subject to careful review by the state commissions. For example, the Massachusetts Department of Public Utilities reviews purchases outside bidding. Similarly, in its bidding rules, the Virginia State Corporation Commission suggests that the utility or developer be required to seek commission approval to negotiate outside of bidding. Furthermore, they must demonstrate to the commission that the contract is favorable to the ratepayers but cannot be accommodated in the bidding process.

Most bidders would favor giving utilities the flexibility to contract outside bidding in special circumstances subject to careful review by the state commissions.

In accordance with the Massachusetts and Virginia bidding procedures, NIEP recommends that:

1) With commission approval, utilities should establish guidelines for negotiating and contracting outside bidding. Guidelines should describe the kinds of projects eligible for contracts outside bidding and a method for keeping the pricing and terms and conditions of these contracts comparable with either avoided-cost or the contracts obtained through formal bidding procedures;

2) The burden of persuasion on the merits of a projects should lie with the developer;[4] and,

3) The state commissions, should review the impact of contracting outside of bidding on the bidding system as a whole and ensure that the fairness of the overall competitive procurement system in the state is maintained.

D. Bidding Into Public Power RFPs

Many public power entities are now using competitive bidding as a method to meet resource needs. Bidders have expressed concern that: 1) some public power entities view bidding RFPs as a way to gain bargaining leverage over traditional utility sellers, not as a serious means of acquiring new resources; 2) the solicitations of public power entities are less "sophisticated" than investor-owned utilities; and 3) no impartial entity oversees the bidding procedures of public power RFPs or provides any avenue of appeal if mistakes are made.

It is clear from the survey that bidders are not convinced about seriousness with which public power entities approach bidding. Many believe that a number of the rural electric cooperatives who have issued bids have done so only to satisfy the Rural Electrification Administration guidelines. There is some evidence to bear this out — to date, of the six solicitations where all bids were rejected, four were conducted by municipal utilities or rural electric cooperatives. Furthermore, no project has yet been awarded a contract through a public power bid. Finally, in the remaining ten public power solicitations, either the filing period has not yet closed or awards have not yet been made.

If no winners materialize from public power RFPs, bidders will come to feel it is not worth bidding, stay away from these solicitations and competition will ultimately fail. Seeing public power entities go through the full cycle from RFP design to bid awards, contracting and, finally to successful operation, will help attract bidders to future RFPs.

In view of these concerns, NIEP recommends the following:

1) FERC should delegate to the states authority to oversee bidding by public power entities not subject to state utility regulation. (Examples of this approach abound in federal legislation. PURPA delegates most authority over QFs to the states. The Clean Air Act delegates to the states the authority to issue air permits.) However, FERC should retain authority to oversee and enforce these programs.

2) Where state law permits, state commissions should exercise authority derived from integrated resource planning, siting procedures, and "convenience and necessity" certification processes to exercise more control over public power bidding programs. For example, under Florida's siting laws, all generating facilities in the state over 75 MW, regardless of ownership, must obtain a certificate of convenience and necessity.

3) State public utility commissions should be available to arbitrate disputes between bidders and public power entities. (They may have general authority to do so under PURPA or siting and certificating authority). For example, the Virginia State Corporation Commission is currently involved in an arbitration between a group of project developers and a rural electric cooperative.

E. Treatment of Regulatory Compliance Costs

Unforeseen, "post contract" regulatory compliance costs can present major economic problems for fixed-price contracts. Utility projects may gain a competitive advantage from their ability to pass through these costs, subject to commission review of prudence. However, contract adjustments for developers should not be automatic. This issue demands a level of compromise from both buyer and seller, with strict oversight by the state commission.

Many developers find the notion of straight pass-through of increased costs due to unforseen changes in regulatory compliance ideal. However, it is important to bear in mind that unlike "unregulated" independent developers, utility costs and profits are closely monitored. One can argue, then, that unregulated firms should bear at least some regulatory compliance risk. Moreover, utilities are required to flow decreased regulatory compliance costs back to ratepayers. For example, when the 1986 Tax Reform Act lowered the corporate tax rate, many states and the FERC initiated rate proceedings for utilities to pass the windfall resulting from changes in the tax code back to ratepayers so they would not exceed their regulated rate of return.

NIEP recommends that where a cost increase due to unforeseen changes in regulation causes an economic hardship for a developer, regulators should allow contract amendments that permit:

1) The developer to fully or partially pass unforeseeable costs through, or,

2) The utility and developer to renegotiate contract price.

To be permitted to pass increased costs due to regulatory compliance through to ratepayers or renegotiate, the developer should be required to demonstrate that the changes could not be reasonably foreseen and the resulting cost increases were so large as to threaten the continued economic viability of the projects. Commissions should set standards for each. Standards are necessary to preserve the reliability of these plants for ratepayers and the competitive power option.

F. Treatment of Environmental Externalities

Clearly, consideration of externalities in the utility planning process is a growing phenomenon. As of July 1990, 17 states had adopted rules or policies on the treatment of externalities, and seven other states were developing externalities policies. In addition, at least five of the 17 states require some consideration of externalities in bidding programs.

In developing externalities policies, process is extremely important. The determination of how and what environmental impacts should be included should be made in a public forum, with an opportunity for all affected parties to actively participate in the proceeding. In active and highly responsive power markets, the scope of the externalities policies will affect which technologies are bid and which project wins. States should address the potential consequences of including and excluding certain environmental effects. For example, a state must decide if it is acceptable as a matter of policy if the externality calculation knocks out all potential coal-fired projects. Also, the process should recognize the potential economic impact through rates of lower social costs, but higher actual cost of electricity.

Respondents generally agreed that externalities should be included in the selection criteria of the bidding process. Including externalities in bidding programs creates a level playing field for environmentally clean resources and gives bidders incentives to minimize the total societal costs of their projects. In implementing this aim, NIEP makes recommendations in the areas below:

1) Any externality policy must be applied equally to utility and non-utility supply and demand resources. There is a danger that state commissions, in encouraging utilities to undertake their own programs to increase energy efficiency, may close off competition from more cost-effective, non-utility supply and demand-side providers.

2) While the number of identified externalities and the methods for measuring them differ from state to state, NIEP recommends that commissions review the checklist of externalities to ascertain that they include the societal costs of a broad range of fuels and technologies and are not unduly influenced simply by ease of measurement.

3) The determination of what environmental impacts are to be included and how they are to be measured should be made in a public process, with an opportunity for all potential suppliers and other affected persons to participate.

4) Utilities and state commissions should consider whether the application of externality analysis to project selection should be accompanied by environmental dispatch. This may be a way to deal with the anomaly that externality policies only evaluate the environmental costs of new plants, not the total societal costs of decisions to continue to run older existing plants which may be less efficient and more polluting.

5) Potential suppliers should be permitted to attempt to mitigate or offset some externalities.

6) States should make some attempt to analyze or market-test their externalities valuations before applying them wholesale to the planning process.

Sulfur Dioxide Emission Allowances

Moreover, states will directly confront externalities as they begin to implement the allowance trading program of the Clean Air Act Amendments of 1990. States should not permit the allowance program to interfere with competitive bidding. State policies should encourage fluidity in the allowance market. Also, state policies regarding treatment of allowance trading should recognize the existence of competitive power markets and potential power suppliers other than jurisdictional utilities.

1) For competitive power markets to flourish, emission allowance markets must flourish as well. State regulators should recognize that most non-utility generators, because their existing plants are clean, will not have opportunities to acquire allowances through over-compliance. To build new plants, non-utility generators will have to rely on the allowance market. State regulators should strive to assure that bidders who need allowances are afforded a reasonable, fair, and timely opportunity to obtain them.

2) The allowance requirement should not be allowed to tilt competition in favor of "build" over "buy" options. For the benchmark or avoided utility plant, the cost of allowances should not be zero; they should be priced at market. States may also want to consider holding allowances "in trust" for winning bidders or auctioning allowances held by host utilities to bidders.

G. Treatment of Repowered Plants in Bidding

Repowered or life-extended plants raise interesting policy issues in the resource selection process. On the one hand, a repowered plant may have lower capital costs relative to "greenfield" plants since the bulk of its capital costs have been paid by the utility's ratepayers in the past. On the other hand, the operating and maintenance costs of a repowered plant might be higher and will likely rise over time, compared to greenfield plants, since they use fuel less efficiently and will require more maintenance as they age.

In addition, commissions should ensure that ratepayers who have paid for this plant over time can be adequately compensated if the plant is removed from the utility's ratebase and bid competitively. If the repowered plant instead becomes the utility's avoided or benchmark plant, how should its price be compared to competitive supply and demand offers? Also, one should consider environmental impacts based not only on a repowered plants' relative emission limits, but also on the actual emissions levels resulting from the fuel inefficiency of a plant that is 30 years old or more.

Finally, utilities and commissions must develop fair and consistent methods of comparing the costs of a repowered plant with other resource options. Developing a measure of "fair market value" for repowered plants to be used in these comparisons was widely supported by bidders.

NIEP recommends that state commissions adopt the following treatment of repowered plants in competitive procurement:

1) Utilities who wish to use a repowered plant should be required to submit a sealed bid and be held to its bid price should it be selected.

2) The cost of repowering should be adjusted to reflect the shorter expected lifetime of repowered plants, and include potential penalties for decreased reliability, increased maintenance cost, lower efficiency, and greater environmental impacts versus a new plant.

3) State commissions should have authority to approve in advance any spin off of fully depreciated repowered units to separate affiliates.

Finally, commissions should consider whether depreciated utility assets may be offered for bid. It can be argued that ratepayers have paid for these assets, and they deserve to have those assets put to the best and highest use. A developer may be able to create more value from a depreciated asset such as a powerplant or plant site than the utility. Certainly, utility shareholders would have to be appropriately compensated in these situations. As good, permitted sites become increasingly scarce, states may want to consider policies that will enable existing sites to be used for highest benefit of the ratepayer. Ratepayers should be able to receive the higher of the best bid for the asset or the "fair market value" as determined by an independent appraiser for an asset to be removed from rate base.

Developing a measure of "fair market value" for repowered plants to be used in these comparisons was widely supported by bidders.

H. Impact of Purchased Power on Utility Finances

Some utilities have asked their state regulators to consider the alleged negative effect which third-party power purchases may have on utility cost of capital. They also state that independent power producers may gain an unfair competitive advantage by transferring certain regulatory, market, and operating risks to their utility purchasers.

With all the attention that the potential impact of power purchases on utility credit ratings is getting, it is important to separate the myth and legend from fact. Clearly, credit rating agencies will consider any contractual commitment which affects a utility's balance sheet. Also, project financiers will consider the credit-worthiness of the purchasing utility before financing a non-utility powerplant.

But the whole issue must be taken in context. It important to remember that credit ratings are subjective and the rating agencies have suggested no hard and fast rules for evaluating power contracts. The purchasing utility can effectively mitigate any potential impact by engaging in prudent buying practices to satisfy both the rating agencies and their commissions. For this credit rating concern to have merit, two simultaneous and unlikely events must occur: 1) the utility must either lack or fail to exercise its leverage in contract negotiations to adjust for the perceived risk; and 2) the state commissions, with authority over the purchasing utility, must be unwilling to intervene in a procurement process which supposedly puts the utility and its ratepayers at a disadvantage.

As commissions confront this issue, NIEP recommends following guidelines:

1) Regulators should not look at the impact of purchase obligations on utility credit rating in a vacuum. They must also consider the credit impact of utility decisions to build rather than buy. In the 1980s, the surest way for a utility to improve its credit rating was to defer or disavow new utility plant construction.

2) Regulators should consider how performance criteria and other contractual guarantees, including security deposits and liquidated damage provisions, mitigate any impact on the utility's contractual commitments;

3) Regulators should treat equally all power purchases which involve a utility committment to make long-term power purchases, including system sales;

4) Regulators should fairly evaluate the impact of contract power obligations against the potential impact on their cost of capital of the alternative, namely, building the plant themselves; and

5) Regulators should recognize enhanced reliability from diversified and dispersed supply sources.

I. Incentives for Utility Purchase of Supply and DSM Resources

Since purchases of power from cogeneration, renewable resources, DSM providers or other non-utility sources add nothing to utility profits, some utility executives and state regulators have proposed that utilities receive financial incentives for purchasing non-utility resources. The current regulated system permits utilities to gain profits only when additions are made to ratebase through construction. Incentives, they argue, are necessary to make utilities indifferent among alternatives such as their own construction, power purchases or demand-side management. Over the past several years, a number of commissions have instituted financial incentives for utilities to pursue conservation and demand-side management programs although only one state has adopted an incentive program for supply purchases to date.

Policies which offer utilities incentives to purchase power or adopt conservation strategies could serve independent power producers' self interest but are difficult to implement without sending utilities potentially inappropriate signals. Most incentive programs (all but one are demand-side only) currently offer utilities the opportunity to earn a profit based on the savings of adopting cost-effective conservation.

NIEP opposes financial incentives to encourage utilities to purchase supply resources. Utilities have a public service obligation to acquire the most cost-effective resources regardless of whether they make contributions to their ratebase and, therefore, their shareholders.

Moreover, consumers may lose some of the benefits of purchased power or demand-side management by being required to pay a premium above the actual cost of the resource. Finally, particularly with incentives for power purchases, since the utility has the opportunity to build or compete to build the capacity, in a sense, the utility is earning a profit for being uncompetitive. Parallel financial treatment with supply-side resources for conservation may be necessary because successful conservation programs diminish kWh sales and in concert with the lag in recovering program cost, can lead to revenue erosion for the utility.

If incentives for utilities to undertake demand-side management programs or to purchase power are implemented, strong regulatory checks are necessary to ensure that:

- Cost estimates for avoided and actual resources are accurate;
- The incentive payment is directly tied to performance of the utility managing the purchase;
- Demand-side management, whether delivered by the utility or independent suppliers, is subject to measurement, monitoring, and verification to ensure that promised energy savings are in fact delivered;
- Utilities are encouraged to invest in the most efficient resource (taking into account all alternatives);
- Utilities are penalized for poor performance in managing contracts; and,
- Utilities should not ignore the existence of third-party, demand-side management providers who may be more cost-effective than utility providers.

Some have suggested incentives (such as shared savings or "equity kicker") as a way to deal with potential credit rating impact of power purchases. If there is, in fact, an uncompensated cost to ratepayers, commissions should, on a case-by-case basis, use the tools of traditional ratemaking to establish its existence, cost causation and find appropriate ways to deal with the cost. Establishing policies for supply-side incentives is not the answer.

NOTES

1. *Independent Power Report*, "TU Seeks to Weigh Non-Utility Bids Against its Own Plans for 2,162 MW," April 26, 1991, page 1.

2. *Robertson's Current Competition*, May 1991, page 16.

3. National Independent Energy Producers, *Bidding For Power: The Emergence of Competitive Bidding in Electric Generation*, Chapter II.

4. For example, Massachusetts allows purchases outside bidding in special circumstances where demonstrable benefits become available to ratepayers, such as emergency purchases or purchases from facilities using new technologies, unique fuels or which provide other extraordinary benefits. However, each purchase is reviewed on a case-by-case basis where the developer or utility bears the burden of persuasion.